2010/2011 Annual Report

BRITISH COLUMBIA UTILITIES COMMISSION

Contents

5 Message from the Chair

6 Organizational Overview

17 The Year in Review

25 Finance and Administration

32 Summary of Decisions, Reasons for Decision and Negotiated Settlements issued in 2010/2011

53 APPENDICES

61 I Staff List

62 II Regulated Utilities

66 III Natural Gas Marketers Licensed in 2010/2011

67 IV Domestic Electricity Sales in 2010

68 V Domestic Gas Sales in 2010

69 VI Main Electric Transmission and Power Generating Facilities (Map)

70 VII Natural Gas and Gas Liquids Utilities (Map)

71 VIII Performance Indicators

Hearing/Alternative Dispute Resolution Days (Fiscal 2010/2011)

Customer Complaints and Inquiries (Fiscal 2010/2011)

Gas Marketer Complaints/Disputes

Staffing Levels

Directives Issued

Commission Expenditures and Cost of Regulation per Customer

Cost of Energy Regulation per Equivalent Gigajoule of Energy Sold

Cycle Times

80 IX Summary of Commission Orders issued in 2010/2011

101 X Standard Abbreviations & Acronyms

102 XI Glossary of Terms

106 XII Energy Conversion Factors

The Commission's mission is to ensure that ratepayers receive safe, reliable and nondiscriminatory energy services at fair rates from the utilities it regulates, and that shareholders of those utilities are afforded a reasonable opportunity to earn a fair return on their invested capital.

Message from the Chair

The significant change that dominates our joint agendas has continued to challenge the BC Utilities Commission, the utilities we regulate and the public stakeholders who participate in our proceedings.

Change in terms of addressing opportunities and challenges in implementing energy policy, conservation initiatives, energy supply, new technology, refurbishment and expansion of infrastructure and the evolution of the industry. Basic automobile insurance, which the Commission also regulates, continues to evolve as well. Change can be a source of anxiety or motivation and I am proud of how our organization faced these challenges head-on and responded with considerable thought and enthusiasm. Change was a part of my message last year and it is clear that it will be at the forefront of our agenda for the foreseeable future. The Commission must continue efforts to build a depth of capability to maintain effectiveness in this dynamic environment.

The Commission objectives set a couple of years ago continue to provide the focus necessary to meet this challenge. I am particularly pleased with the continuing progress in building our professional capabilities; growing as a learning organization and adding to our professional capacity is a major achievement. Stakeholder engagement also paid dividends in better understanding new issues as they arose and developing ways to effectively deal with them within the regulatory environment.

The product of the Commission's work is the decisions it makes on the issues that come before it. The Commission made a commitment to write clear, well reasoned plain language decisions, particularly on matters that are often complex and technical in nature, so as to ensure that those who are affected can easily engage in the decisions made and reasons given. In spite of the progress made in most areas I remain dissatisfied that more was not achieved in advancing our use of technology. Looking forward, more progress must be made to employ the technology tools available to assist the Commission in its work, perhaps outside of the standard information technology services available through government.

The success of the Commission in carrying out its important work on behalf of the citizens and businesses of British Columbia is the result of the ongoing dedication and professionalism of our staff and Commissioners. This Annual Report provides an opportunity to formally recognize and thank them for their contributions and successes. I also thank the many stakeholders who participated in Commission processes in the past year.

The content of the Annual Report details in considerable depth the work of the Commission over the past year. This Report fulfills the requirement of Section 12 of the Utilities Commission Act as well as the Budget and Transparency Act. I respectively submit this Report to the Lieutenant Governor in Council.

Len Kelsey
Chair and Chief Executive Officer

Overview

INTRODUCTION

The Commission regulates energy utilities and basic mandatory automobile insurance in British Columbia. The Commission is an independent, regulatory agency of the Provincial Government operating under and administering the *Utilities Commission Act*. As an administrative tribunal, the Commission has responsibilities under the *Administrative Tribunals Act* to ensure its process is fair, transparent, and inclusive; and its decisions are principled and based on sound evidence brought forward by well represented parties. The Commission is self-funded meaning its costs are primarily covered through a levy to the organizations it regulates. In carrying out its responsibilities, the Commission continuously seeks innovative ways to increase efficiency, respond to change, and engage its stakeholders in a meaningful way while improving fairness, transparency and inclusiveness of the regulatory process.

REGULATORY RESPONSIBILITIES

The Commission has the responsibility to make quasi-judicial decisions that are fair and considerate of all relevant views. Its proceedings and decision-making process must be open to all relevant stakeholders. Facilitating participation by all affected parties is an important part of the Commission's responsibilities.

In the course of performing its regulatory responsibilities, the Commission fulfills its mission of ensuring ratepayers receive safe, reliable, and non-discriminatory energy services at fair rates from the utilities it regulates, and that shareholders of those utilities are afforded a reasonable opportunity to earn a fair return on their invested capital. All the Commission's activities align with its vision of being a respected regulator of public utilities.

Senior Executive Team
(left to right) : Philip Nakoneshny, Erica Hamilton, Viki Vourlis, Len Kelsey, Doug Chong, Brian Williston & Mark Thomas

Through an open, fair and transparent process the Commission:

- regulates electric and gas utilities within its jurisdiction in accordance with relevant legislation
- ensures compulsory automobile insurance rates offered by the Insurance Corporation of British Columbia are just and reasonable
- adopts and monitors adherence to mandatory reliability standards that are in the public interest
- reviews inquiries and complaints about the actions of regulated utilities and ICBC, and adjudicates gas marketing disputes
- establishes tolls and conditions of service for intra-provincial oil pipelines
- reviews energy-related and basic automobile insurance matters referred to it by Cabinet, which may involve a public inquiry and a report with recommendations to Cabinet
- facilitates public participation and ensures stakeholders have the information required to present their views effectively

The Commission strives to perform its regulatory activities efficiently, in compliance with all relevant legislation and regulations and in consideration of government policies, the business needs of regulated entities and the public interest.

Finance, HR & Administration
(left to right) : Denise Goodard, Viki Vourlis & Kim Brooks

Vision

To be a respected regulator of public utilities.

Mission

To ensure that ratepayers receive safe, reliable, and non-discriminatory energy services at fair rates from the utilities it regulates, and that shareholders of those utilities are afforded a reasonable opportunity to earn a fair return on their invested capital.

Value Statements

The Commission is committed to:

- Ensure arms-length, independent, and accountable regulation of utilities and ICBC.
- Apply regulatory principles, research and industry knowledge to resolve matters concerning public utilities or the regulated portion of automobile insurance.
- Render decisions that are timely, fair, workable, and respected.
- Write high quality decisions, reports, and publications.
- Communicate effectively and transparently with co-workers, utilities, ratepayers, government and the public.
- Promote learning, innovation, creativity and the achievement of professional goals.

THE WAY WE WORK

The Commission relies on the skills, expertise and excellence of Commission staff and Commissioners. Commissioners are appointed by the Lieutenant Governor in Council based on merit. Commission staff are hired by the Commission also based on merit. Commissioner biographies are included at the end of this section.

Commission staff and Commissioners come from diverse backgrounds and include business specialists, economists, professional engineers, accountants, and administrators. All Commission staff and Commissioners share clarity of purpose and the desire to contribute in a meaningful way to the well-being of British Columbians. Commission staff and Commissioners alike are dedicated to excellence and continuous learning while fulfilling their professional responsibilities.

The Commission takes an interdisciplinary approach in carrying out its functions. For example, applications designated to go to a proceeding are assigned a Hearing Team to conduct the review. This team includes staff from the professional divisions, who provide expert analysis, and staff from the Information Services Group, who provide procedural and administrative support. In addition, the Chair assigns a Commission Panel made up of one or more Commissioners tasked with reviewing evidence and making decisions on matters that come before the Commission.

The Commission actively promotes learning and creativity and acknowledges achievement of personal and professional objectives of its people. The Commission is a place where staff are encouraged to develop unique skills and expertise and are drawn upon as subject matter experts within the organization. In addition, Commission staff and Commissioners regularly attend writing workshops to continue to improve writing capabilities and move the Commission forward in its objective of writing clear, and well-reasoned decisions. Commission staff and other stakeholders also conduct "Lunch and Learn" sessions in various subject areas and all members of the Commission are encouraged to attend. Finally, to continue to develop industry knowledge, Commission staff and Commissioners attend conferences, courses and workshops in relevant areas. Combined, all of these activities move the Commission toward achieving its goal of continuous learning and excellence.

THE BRITISH COLUMBIA UTILITIES COMMISSION ORGANIZATIONAL STRUCTURE

The Commission is made up of several internal divisions, all reporting to the Chair and CEO. The departments include the Financial Administration Office, the Information Services Group, and four Professional Divisions: Strategic Services; Rates & Finance; Engineering & Commodity Markets; and Innovation & Emerging Technologies.

Financial Administration Office

The financial administration office conducts background research and provides decision support for executive policies and a range of administrative, financial, intra-governmental and human resources services. The office offers decision support to the Chair and CEO, Commission staff and Commissioners.

Information Services Group

The Information Services group, led by the Commission Secretary, includes the Assistant Commission Secretary, Customer Choice Administrator, Customer Service Specialist, Web Administrator and several support positions. The Commission Secretary fulfils the statutory duties of the *Utilities Commission Act* as the official contact for both regulated organizations and the public.

The department responds to all requests for information; receives and investigates utility customer complaints; prepares periodic reports and quarterly regulatory updates; provides research support; website services; library services and media interaction; and maintains the Commission's information resources and databases.

Professional Divisions

The professional divisions consist of staff specialists with expertise and experience in the areas of accounting, economics, ratemaking, business, and engineering. In 2010, the Commission introduced a new division focusing on emerging technologies and innovation.

The functions of the divisions include the review of financial, accounting, social, and economic aspects of energy utility activities and ICBC's basic automobile insurance. In addition, in certain matters the adequacy of First Nations consultation is also a consideration. The professional divisions also review energy supply and demand, including conservation impacts, and the reliability aspects of energy production, transmission, and distribution. In considering a matter under review by the Commission, Commission staff have a responsibility to ensure the development of a full record of evidence. Commission staff often advise the Commissioners on technical matters and may provide external expert witnesses to testify at hearings.

The organizational chart below provides an overview of the Commission's structure.

THE BRITISH COLUMBIA UTILITIES COMMISSION ORGANIZATIONAL CHART

OFFICE OF THE CHAIR
Len Kelsey, Chair & CEO

FINANCIAL ADMINISTRATION
Viki Vourlis, Manager of Finance, Human Resources, Administration & Assistant to the Chair/CEO (3)

INFORMATION SERVICES
Erica Hamilton, Commission Secretary (7)

COMMISSIONERS
Alison Rhodes
Peter Vivian
Robert (Bob) Milbourne
Lisa O'Hara
Anthony Pullman
Keith Anderson
Michael Harle
Dennis Cote
Carol Brown
David Morton
Norman MacMurchy (11)

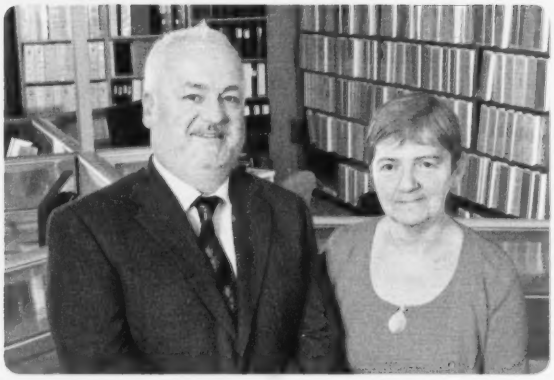
REGULATORY AFFAIRS & PLANNING

STRATEGIC SERVICES
Doug Chong, Director (4)

RATES & FINANCE
Philip Nakoneshny, Director (4)

ENGINEERING & COMMODITY MARKETS
Brian Williston, Director (4)

EMERGING TECHNOLOGIES AND INNOVATION
Mark Thomas, Director (2)



Information Services Department
(top-left) ; Erica Hamilton
(top-right) ; Daniela Guest & Kristen Olsen
(bottom-left) ; Constance Smith, Kathy Grasly & Yvonne Lapierre
(bottom-right) ; Mark Hudson & Alison Cormack

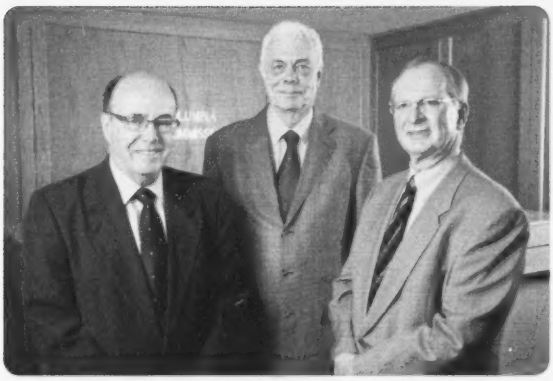
Strategic Services Department
(top-left) ; Eileen Cheng, Doug Chong, Alison Richter & Julie Iran

Rates & Finance Department
(top right) ; Yolanda Domingo, Suzanne Sue, Claudia McMahon, Philip Nakoneshny & Kristine Bienert

Engineering & Commodity Markets Department
(bottom-left) ; Roy Bishop, Don Flintoff, Brian Williston, Todd Smith & Cathy Marr

Emerging Technologies and Innovation Department
(bottom-right) ; Mark Thomas & Tatiana Obrejanu

(top) ; Norman MacMurchy
(middle-left) ; Peter Vivian, Anthony Pullman & Michael Harle
(middle-right) ; Bob Milbourne, Liisa O'Hara & David Morton
(bottom-left) ; Keith Anderson & Carol Brown
(bottom-right) ; Dennis Cote & Alison Rhodes



Commissioner Biographies

LEONARD F. KELSEY,
CHAIR AND CHIEF EXECUTIVE OFFICER

Vice President British Columbia Automobile Association (18 years); Chief Operating Officer, BCAA Insurance Corporation, retired 2002; past Member B.C. Committee, Insurance Bureau of Canada; Public Administrator and past Chair, North Shore Health Region; independent Business Consultant. Prior to appointment as Chair, served as a Commissioner for the British Columbia Utilities Commission from 2003-2008; appointed Chair July 2008.

ALISON A. RHODES,
COMMISSIONER

University of British Columbia, 1976 (B.A. - economics major); University of Western Ontario, 1983 (LL.B, MBA); Called to British Columbia Bar 1984; Practiced law (civil litigation) 1984 to 2004; Vice President, Jardine Lloyd Thompson Canada - 2004 to 2008; appointed December 2007.

DENNIS A. COTE,
COMMISSIONER (PART-TIME)

Simon Fraser University (Bachelor of General Studies); retired in 2007 as the Vice President, Product Development and Support for the British Columbia Automobile Association; held various other executive roles with the BCAA which include Vice President Sales, Director of Travel Services; Merchandise Investment Manager and Store Manager with the Hudson Bay Company, BC Region; Vice President and board member with the Alliance of Canadian Travel Agents of British Columbia; currently a Travel Industry Advisory Group Member with Consumer Protection BC; appointed October 2008.

A.W. (KEITH) ANDERSON,
COMMISSIONER (PART-TIME)

Bachelor of Commerce, University of Alberta, Chartered Accountant; Retired from PricewaterhouseCoopers as partner responsible for PwC's energy utilities practice in Canada: over 35 years experience as a strategic planning, financial, and regulatory consultant in the energy and other sectors including gas, electric and pipeline utilities, financial institutions, telecommunications and transportation companies; independent financial and management advisory consultant serving as a director of and advisor to private corporations; appointed July 2006.

CAROL A. BROWN,
COMMISSIONER (PART-TIME)

Carol Brown is a lawyer and business consultant; practicing commercial law for over 20 years, with experience in the forest industry; mediates work place disputes, facilitates workshops on communication and conflict management, and leads strategy sessions for small and medium sized enterprises. Director, Prince George Airport Authority; CBA Benevolent Society; and member of Environmental Appeal Board; the Oil and Gas Appeal Commission; and Forest Practices Appeal Commission. Past Director with ICBC. Certified General Accountant with a Master's degree in leadership; Currently completing a PhD in Human and Organizational Development; Teaches Human Resources courses at UNBC; appointed November 2010.

MICHAEL R. HARLE,
COMMISSIONER (PART-TIME)

Bachelor of Commerce, (Carleton 1967); Chartered Accountant (Ontario, 1970 and Alberta, 1979) and Certified Management Consultant (Alberta 1979). Over forty years experience as a professional consultant and business executive; retired from IBM as Partner responsible for IBM Global Business Services for the Alberta and Saskatchewan public sectors in health, and education. Spent 35 years with PricewaterhouseCoopers Consulting and its predecessor companies where he was partner responsible for public sector services in the Prairie Provinces and northern Canada; appointed December 2008.

NORMAN E. MACMURCHY,
COMMISSIONER (PART-TIME)

Royal Military College of Canada (Hons. B.A. Economics and Commerce); University of Western Ontario (M.A. Economics); Retired 2006 as Executive Director, Industrial Gas Consumers Association of Alberta. Held various positions with the Alberta and federal governments including Chair, Alberta Petroleum Marketing Commission; Assistant Deputy Minister, Sustainable Energy Development Division, Alberta Department of Energy and Natural Resources; and Chief, Policy Analysis and International Division, National Energy Board; appointed November 2010.

ROBERT J. (BOB) MILBOURNE,
COMMISSIONER (PART-TIME)

University of British Columbia (BASc. Metallurgical Engineering); P.Eng. (B.C., Ontario); Stelco Inc., retired as Senior Executive and Member of the Board of Directors (1996); Principal, Milbourne and Company Business Advisors (1997); Hatch Associates Ltd., Director (1997-2002); Bruce Power Inc., Director (2001-2005); Member Ontario Human Rights Commission (1991-1996); Member, B.C. Securities Commission (2002); appointed August 2003.

DAVID MORTON,
COMMISSION (PART-TIME)

University of Toronto (B.A.Sc. 1977); P.Eng. (British Columbia); Licensed Accountant. (Society of Management Accountants Canada 1986); Information Technology consultant since 1993; appointed November 2010.

LISA A. O'HARA,
COMMISSIONER (PART-TIME)

University of British Columbia, 1976 (M.Sc., Business Administration). Certified General Accountant, 1984. A senior pipeline executive, retired from Terasen Pipelines in 2004 as Vice President, Financial Services and Regulatory Affairs after 21 years of service. Prior to the career in the energy industry, enjoyed an eight year career in the airline industry employed by CP Air in various financial and regulatory affairs roles. Served as Executive-In-Residence at Sauder School of Business from 2005 to 2009. As a graduate of Institute of Corporate Directors, certified with the ICD.D designation in 2006, serves as a professional corporate director on various corporate boards; appointed January 2005.

ANTHONY J. PULLMAN, COMMISSIONER (PART-TIME)

Keble College Oxford (B.A. 1967, M.A. 2001) Chartered Accountant 1970; retired from the ATCO Group in 2004 after 24 years of service - Vice President Controller Alberta Power Limited (1980-1985); Vice President Controller and Vice President Planning and Budgeting ATCO Ltd. (1985-1993); Senior Vice President Finance ATCO Power Ltd (1993-2004); Chairman Calgary District Hospital Group (1989-1991); Chairman Alberta Blue Cross Plan (1996-1998); appointed March 2006; term extended under section 7 of the *Administrative Tribunals Act*.

PETER E. VIVIAN, COMMISSIONER (PART-TIME)

University of Toronto, 1965 (Bachelor of Applied Science - Electronics); University of Western Ontario (Bachelor of Law); Flight Lieutenant, RCAF; Professor of Law at the universities of Western Ontario, Ottawa and Victoria; General Manager, Canadian Law Information Council (1975-77); various positions with the BCE Inc. group of companies (1977-97); Vice President and Chief of Staff, The Business Council on National Issues (now the Council of Canadian Chief Executives) (1982-84, 1989-90); Executive Director, Telecommunications, CRTC (1998-2000); Principal, Vivian Associates, Consultants to Management (2000-present); appointed August 2003; term extended under section 7 of the *Administrative Tribunals Act*.

(top) ; Len Kelsey
(middle) ; Anthony Pullman
(bottom) ; Lisa O'Hara

SPECIAL DIRECTIVES

Following is a general description of the Special Directives received during 2010. The complete text of the Special Directives is available on the Commission's website at www.bcuc.com/About the BCUC/Special Directives.

Order in Council No. 224

Approved April 29, 2010 – Amendments to Section 1, Section 3(1) and Section 4(1) of Special Direction IC2 to the British Columbia Utilities Commission, BC Reg. 307/2004 with respect to the Insurance Corporation of British Columbia.

Order in Council No. 431

Approved June 24, 2010 – Amendments to the Remote Communities Regulation section 2(a) by striking out "90 metres" and substituting "200 metres" and by adding in the Schedule – 6) Tsay Keh Dene and 7) Fort Ware.

Order in Council No. 503

Approved July 29, 2010 – Ordered that section 2 of the *Haida Gwaii Reconciliation Act* be brought into force and that amendments to the Close Areas Regulation, Hunting Regulation, Special Direction No. 10 to the BCUC and the Water Regulation be amended to reflect the name change from "Queen Charlotte Islands" to "Haida Gwaii."

Order in Council No. 694

Approved November 4, 2010 – Electricity Self-Sufficiency Regulation brought into force.

Order in Council No. 694

Approved May 27, 2010 – Letter of Direction from the Minister of Public Safety and Solicitor General to the Insurance Corporation of British Columbia with respect to capital requirements of universal compulsory automobile insurance.

Ministerial Order No. M277

Approved October 4, 2010 – Clean or Renewable Resource Regulation brought into force.

Ministerial Order No. M284

Approved October 18, 2010 – Exempt Projects, Programs, Contracts and Expenditures Regulation brought into force.

Ministerial Order No. M314

Approved November 5, 2010 – Authorization for Burrard Thermal Electricity Regulation brought into force.

Ministerial Order No. M361

Approved December 7, 2010 – Smart Meters and Smart Grid Regulation brought into force.

Order in Council No. 015

Approved February 2, 2011 – Amendments to Special Direction No. 9 to the British Columbia Utilities Commission with respect to the issuance of a certificate in respect to an electricity transmission project, to a utility other than BC Hydro.

Order in Council No. 020

Approved February 2, 2011 – Amendments to Heritage Special Direction No. HC2 to the British Columbia Utilities Commission, B.C. Reg. *158/2005*, effective April 1, 2011.

Order in Council No. 021

Approved February 2, 2011 – Amendments to Heritage Special Directive No. HC1 to the Hydro and Power Authority, Order in Council 112512003, effective April 1, 2011.

The Year in Review

HIGHLIGHTS IN THE COMMISSION'S OPERATIONS

Commitment to Efficiency, Continuous Learning and Capacity Building

The Commission is committed to making well reasoned, clear and transparent decisions that are in the public interest. The subject of many applications is often technical and complex resulting in the challenge of writing clear decisions that can be well understood and supported by those who are most affected. Building this type of support for Commission decisions is achieved in part through a writing style that is inviting and easy for the general public to understand, yet maintains the formal and quasi-judicial discipline required. The reasoning must also be straightforward and clear. Throughout the year, all Commission staff and Commissioners participated in interactive writing workshops with the express goal of writing the highest quality decisions possible.

To continually improve efficiency, the Commission initiated a review of the Negotiated Settlement Process Guidelines. The Negotiated Settlement Process is an efficient and effective way to resolve certain matters that come before the Commission and often result in more innovative solutions than the traditional adversarial process. The review of the Guidelines gathered stakeholders to address their concerns with current Negotiated Settlement practices and to build on the efficiencies of the current process.

With the goal of improving efficiency in the regulatory process, Commission staff also initiated planning meetings with utilities prior to the beginning of large or more complex regulatory proceedings to discuss anticipated reporting requirements and information expectations. Early results have been positive.

Cathy Marr

Ultimately, the ability of the Commission to effectively carry out its mandate in the most efficient way is a function of the quality and unique competencies of Commission staff and Commissioners. Considerable progress was made this year in building our capacity in this area.

Adaptation to the Clean Energy Act

The *Clean Energy Act* was passed in BC on June 3, 2010. It is a legislation that includes 16 energy objectives focused on ensuring energy self sufficiency, reducing green house gas emissions from generation, and supporting the development of lower carbon technologies. The *Clean Energy Act* presented an opportunity and necessity for the Commission to evolve and modernize processes and skill sets in order to adequately consider and reflect on the objectives and goals of the Act in our decision making. The transition from traditional energy sources and delivery methods to a greener and more sustainable energy portfolio requires the Commission to proactively engage with energy stakeholders. To support this modernization, the position of Director - Emerging Technologies & Innovation was created with the principle mandate of developing and maintaining an understanding of new technologies and how these will impact the energy and regulatory environment in BC.

The *Clean Energy Act* requires BC Hydro to submit an Integrated Resource Plan presenting its plans to achieve electricity self-sufficiency and other objectives to the Minister of Energy for approval by December 2011. The *Clean Energy Act* directive replaces BC Hydro's requirement to submit a similar plan to the Commission as previously required by the *Utilities Commission Act*. BC Hydro was directed to consult broadly with all stakeholders in the development of the IRP and thus formed a technical advisory committee consisting of 11 organizations/associations, including Commission staff. By the end of March 2011 the technical advisory committee held three sessions to review and discuss BC Hydro's Integrated Resource Plan.

Carbon Neutral Committee

The Commission formally established its 2010 greenhouse gas inventory in accordance with the GHG Protocol. GHG containment is a priority within the Commission and since it began tracking GHGs, the Commission has implemented measures in areas under which it can have an impact on. These activities have resulted in a significant reduction in paper use with associated GHG emissions dropping by one third from 2008 to 2010.

Peter Vivian

To continue this initiative, the Commission established a Carbon Neutral Committee mandated to continue to assess and recommend improvements to the way we conduct our business.

Terasen Gas – Fortis Energy – Purchase and Name Change

Terasen Gas has been a part of the Fortis group of companies since 2007. The Fortis companies in BC employ more than 2,000 British Columbians and deliver approximately 21 per cent of the total energy consumed in BC to more than 1.1 million customers in 135 communities.

Effective March 1, 2011 the Terasen group of companies were renamed to share a common brand name – FortisBC. To align with Decisions made during this reporting year, the Commission continues to use the Terasen Gas name in the matters identified in this Annual Report.

HIGHLIGHTS IN ELECTRICITY REGULATION

The implementation of the *Clean Energy Act* resulted in the merger of the British Columbia Transmission Corporation and BC Hydro. The date of amalgamation was July 1, 2010; however, to accurately reflect Decisions made in this reporting year, the British Columbia Transmission Corporation is still identified separately in this report.

In 2010, the electrical industry saw increasing pressures to strike a balance between rate increases required to support aging infrastructure in the province, increasing costs for power purchases, and sustainable rate making strategies. FortisBC's rate increases were 6.0 percent in calendar year 2009 followed by 5.20 percent in calendar year 2010. BC Hydro's rate increase for its fiscal period ending March 31, 2011 was 7.29 percent.

(left to right) ; Mark Hudson, Alison Richter & Todd Smith

BC Hydro Large General Service Rate

On October 16, 2009, to add to its conservation rates for industrial and residential customers, BC Hydro applied for a new rate for its existing Large General Service class – typically commercial and industrial customers. The existing rate for this class was a declining block rate whereby customers paid less per unit of energy as their consumption goes up. BC Hydro's main objective to change the rate structure was to encourage energy conservation since a declining block rate inappropriately encourages electricity consumption. After a negotiated settlement process in which a number of Interveners were present, an agreement was approved by the Commission on May 14, 2010. The final agreement split the existing class into two - the Large General Service and Medium General Service and approved an inclining block rate, where the cost of energy per unit increases as consumption goes up, for both classes. The Large General Service rate was implemented on January 1, 2011 and the Medium General Service rate will be implemented in phases on April 1, 2012, 2013 and 2014.

FortisBC Inc. 2009 Rate Design and Cost of Service Study

On October 30, 2009, FortisBC Inc. filed its rate design and cost of service study. A public oral hearing took place in Kelowna in May 2010, which explored a wide range of issues for all customer classes. The proceeding had active Interveners including municipal utility customers, an irrigation ratepayers group, corporate customers of FortisBC, a group representing customers with low or fixed incomes, and three private citizens. The Commission Order and Decision released on October 19, 2010 directed Fortis to, among other things, re-run the cost of service study with prescribed adjustments, develop an inclining block rate for its residential customers, and adjust its rates to achieve a revenue to cost ratio of one for each rate class.

BC Transmission Corporation ILM Transmission Project Court of Appeal Reconsideration

The Interior to Lower Mainland Transmission Project is a 500 KV transmission line from Merritt to Coquitlam that passes through numerous First Nations claimed territories. On August 5, 2008, the Commission granted a Certificate of Public Convenience and Necessity for

the Project. In February 2009, the BC Court of Appeal suspended the Certificate and directed the Commission to consider BC Transmission Corporation's First Nations consultation on the Project. Seven First Nations groups intervened in the reconsideration representing 31 First Nations and 3 Tribal Councils. All the Interveners alleged that consultation had been inadequate. A 13 day oral public hearing took place in 2010. Subsequently, 2 First Nations Interveners withdrew from the proceeding stating consultation had been adequate. On February 3, 2011, the Commission issued its Decision wherein it found that consultation had been adequate with 5 First Nations and 1 Tribal Council but inadequate with the remaining 13 First Nations and 2 Tribal Councils. The Commission directed consultation on the specific issues where consultation was found inadequate and a report to be filed on the further consultation with an opportunity for the First Nations to respond. After review of the report, scheduled for June 2011, if the Commission deems the consultation adequate, it will lift the suspension on the Certificate.

BC Mandatory Reliability Standards

Following the massive electrical power outage in North America's northeast in 2003 that lasted several days and affected an estimated 50 million people, a joint US-Canadian task force was established to review the incident. As a result, the task force recommended that reliability standards be made mandatory and enforceable with sanctions to apply in instances of non-compliance. In order to access the North American electrical power grid, each jurisdiction must implement a regime to ensure compliance with certain standards. In 2008, the *Utilities Commission Act* was amended to provide a framework for the Commission to implement mandatory reliability standards for the bulk transmission system. The Rules of Procedure for the administration and enforcement of the standards identify two significant processes: registration, which determines which entities must register and a process for doing so; and the compliance monitoring program which monitors and assesses compliance with the Standards. The registration phase has progressed relatively smoothly with 31 entities registered and the Commission receiving and approving several mitigation plans. The compliance and monitoring phase commenced recently and the Mandatory Reliability Standards audit schedule begins in the fall of 2011.

(left) ; Yvonne Lapierre & (right) ; Constance Smith

BC Hydro Remote Community Electrification Program

The Remote Community Electrification Program arises from the Remote Communities Regulation issued in conjunction with Special Direction 10 to support the 2007 Energy Plan. This initiative allows BC Hydro to offer electric utility service to interested and eligible remote communities. Nine remote communities have been identified in the regulation and the Commission has approved the following: Toad River (electrified 2009), four Southern St'at'imc Communities (connected 2011), Tsay Keh Dene, Fort Ware and Elhlateese (approved 2011). In the BC Hydro Annual Report filing on the Program, the forecasted cost to implement the program to date is $145,000 to $173,000 per permanent residential customer.

HIGHLIGHTS IN NATURAL GAS REGULATION

The Commission sets the commodity price for natural gas and propane for the utilities under its jurisdiction. Natural gas commodity rates continued to experience downward pressure over the past year due to reduced demand for gas and a surplus of North American supply arising from the continuing shale gas boom. Gas prices remain low compared to historic levels and relative to the price of oil. Propane prices, in contrast to natural gas prices, have continued to increase in connection with rising oil prices.

Terasen Gas Biomethane Application

As part of Terasen Gas Inc.'s move to develop new initiatives that extend its business model in alignment with the provincial energy policy and the *Clean Energy Act*, Terasen filed an application for a biomethane business model. The model offers customers the option of notionally purchasing biomethane at a premium rate. The biomethane will initially be supplied by two projects, one in which Terasen undertakes the upgrading as part of the regulated service and one in which the upgrading is undertaken by an independent operator. The application was approved on a test basis for a two-year period to allow Terasen an opportunity to gain experience and undertake the necessary analysis to determine the appropriate program model for the longer term and to get a better sense of the full market potential for biomethane.

The Commission made no finding on the issue of Terasen's proposed role in the upgrading business and directed the upgrading business to be kept sufficiently separate so as to be severable if the Commission were to determine in the future that this function should be conducted through a non-regulated entity.

Terasen Utilities Long Term Resource Plan

On July 15, 2010, Terasen Utilities filed its 2010 Long Term Resource Plan. The 20-year resource plan

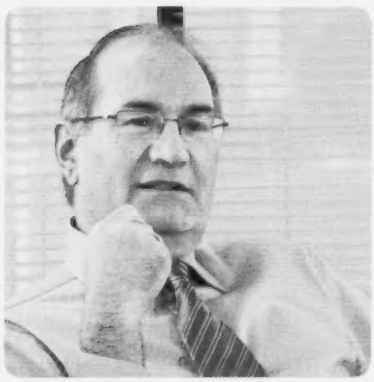
(left) ; Alanna Gillis & (right) ; Tatiana Obrejanu

presented Terasen Utilities' planning environment, the future needs of the utilities and an action plan for the next four years. The plan did not include projects requiring Commission approval; the Utilities requested only for the Commission's acceptance of the Long Term Resource Plan.

In the Decision rendered on February 11, 2011, the Commission accepted the plan. The Commission clarified for the Utilities what was meant by "acceptance" and set out directives related to a number of areas which could be improved in the next plan. The Decision also contains the Commission's comments on the new initiatives being pursued by the Utilities, including issues arising from the new initiatives significant enough to warrant a separate hearing.

PNG Capital Structure and Equity Risk Premium

On July 16, 2009, Pacific Northern Gas (PNG) and its wholly owned subsidiary PNG (Northeast) jointly filed a Capital Structure and Equity Risk Premium application. PNG applied to have the allowed 40 percent common equity ratio for the Western Division increased to 47.5 percent, and to have the allowed 36 percent common equity thickness for both Divisions of the Northeast



(left to right) ; Daniela Guest, Roy Bishop & Brian Williston

increased to 42.5 percent. PNG also applied for the equity risk premium to be set at 75 basis points above the Commission's benchmark utility return on common equity for all three divisions.

The application went to a negotiated settlement process on April 26 and 27, 2010. An agreement was reached on May 12, 2010 and was approved by the Commission on May 20, 2010. The approved negotiated settlement sets, among others, the Western Division's allowed common equity thickness at 45 percent and the two Divisions in the Northeast's allowed common equity at 40 percent. The equity risk premiums were established at 65, 40 and 65 basis points for the Western Division, Fort St. John/ Dawson Creek Division, and Tumbler Ridge Division, respectively.

HIGHLIGHTS IN AUTOMOBILE INSURANCE REGULATION

ICBC Streamlined 2010 Revenue Requirements

On April 6, 2010, in the interest of efficiency, the Commission approved a streamlined rate setting process for ICBC, which created a tiered approach to the annual setting of Basic Insurance rates. An actuarial rate indication above 2.5 percent will require a full revenue requirement application review process while a rate indication of 2.5 percent or below qualifies for a streamlined rate review process. If a rate indication is within +/- 1 percent and ICBC does not seek a rate change, ICBC has the option to file an Actuarial Certificate and supporting documentation to set the Basic Insurance rates.

On May 31, 2010, ICBC submitted a Revenue Requirements application for a 1.9 percent rate decrease for Basic Insurance. After a public review of the application, the Commission directed a further 0.5 percent rate reduction for adjustments to operating costs, resulting in a total 2.4 percent Basic Insurance rate reduction effective November 1, 2010. In addition, the Commission accepted ICBC's plan for its Minimum Capital Test management plan including a provision of the capital maintenance provision in the policy year rates.

HIGHLIGHTS IN OPERATIONAL PERFORMANCE

Proceeding Days

The number of proceeding days declined from 64 days in 2009/2010 to 37 days in 2010/2011 (including hearings, procedural conferences, alternative dispute resolution, workshops, Community Input Sessions, and meetings related to annual reviews of Performance-Based Regulation agreements). There were 12 oral public hearing days in 2010/2011, as compared to 26 in 2009/10. There were 13 alternative dispute resolution days in 2010/2011 and 12 days dedicated to procedural conferences and workshops. A total of 30 applications were reviewed through a written hearing process.

A summary of the decisions and orders issued by the Commission in 2010/2011 can be found commencing on pages 32 and 80, respectively of this Annual Report.

The Commission has the authority to grant cost awards to interveners in proceedings before the Commission. Following a review, the Commission approved revised Participant Assistance Cost Award Guidelines in 2007 to ensure interveners' submissions are useful and not duplicative of other interveners' efforts, and that costs claimed are reasonable. In 2010/2011, the Commission issued 33 participant funding decisions totalling $1,831,922.86 down from the 37 funding decisions totalling $2,887,875.33 in 2009/2010.

Senior Executive Team
(left to right) : Viki Vourlis, Philip Nakonechny, Mark Thomas, Doug Chong, Len Kelsey, Brian Williston & Erica Hamilton

The costs of the Commission can be measured by cost per utility customer and cost per unit of energy sold. In fiscal year 2010/2011, the cost of regulation per customer[1] was $0.95[2] down from $1.17 in 2009/2010, and the cost of regulation per British Columbia resident[3] was $1.33 for 2010/2011 down from $1.48 for 2009/2010. The cost of regulation per gigajoule of energy sold in 2010/2011 was 1.54 cents, down from 1.68 cents in 2009/2010. The total expenditure for fiscal year 2010/2011 was $6,031,155.17; the approved budget was $6,211,000.00.

During the 2011/2012 fiscal year, the Commission expects to review the following major applications:

British Columbia Hydro and Power Authority

- F2012 - F2014 Revenue Requirements
- Ruskin Dam Safety and Powerhouse Upgrade
- Residential Inclining Block Tier 2 Re-Pricing
- Remote Community Electrification Program CPCNs and Annual Report
- Rate Schedule 3808 Agreement (FortisBC Inc. Power Purchase Agreement)
- Tariff Supplement No. 6 and Transmission Extension Policy
- Dawson Creek/Chetwynd Area Transmission Upgrade
- Demand Side Management Expenditure Schedule for F2012 and F2013
- John Hart Rehabilitation Upgrade Project

1 *Includes customers of ICBC and regulated utilities*
2 *All figures reported in 2010 dollars*
3 *Census Canada 2010 for British Columbia*

(left to right) : Bob Milbourne, Eileen Cheng, Brian Williston & Alison Cormack (back row left to right) : Julie Tran & Yolanda Domingo

Corix Multi-Utiltiy Services Inc.

- UniverCity Development Neighbourhood Utility Service Certificate of Public Convenience and Necessity

FortisBC Inc.

- Adaptive Street Lighting Rate
- Residential Inclining Block Rate
- 2012 Revenue Requirements with Integrated System Plan & Residential Plan Update
- Advanced Metering Infrastructure Certificate of Public Convenience and Necessity
- Long-term Facilities Solution for Kootenay Operations Centre Certificate of Public Convenience and Necessity
- Transmission Stepped Rate

FortisBC Energy Inc./ FortisBC Energy (Vancouver Island) Inc./ FortisBC Energy (Whistler) Inc.
(formerly Terasen Gas Inc./Terasen Gas Vancouver Island Inc./Terasen Gas Whistler)

- FEVI Mt. Hayes LNG First Nation Interest
- FEI Discrete Energy (Geo) and District Energy Systems (DES)
- FortisBC Energy Utilities 2012 - 2013 Revenue Requirements & Gas Utilities Amalgamation
- FEI Huntingdon Bypass Certificate of Public Convenience and Necessity
- FEVI Municipal Operating Agreements

Insurance Corporation of British Columbia

- Rate Design Adjustments
- Actuarial Certificate or Streamlined Revenue Requirements
- Driving Record Model (DRM) Rate Design application

Pacific Northern Gas Ltd./
Pacific Northern Gas (N.E.) Ltd.

- KSL Project Pipeline Certificate of Public Convenience and Necessity
- PNG West 2011 Resource Plan for the Pipeline System
- PNG West 2012 Revenue Requirements
- PNG (N.E.) 2012 Revenue Requirements

Finance & Administration

F2011 REVENUES AND EXPENSES

The Commission is authorized to recover its costs from regulated utilities and pipeline companies by fixing levies according to section 125 of the *Utilities Commission Act* and parameters set out in Levy Regulation, BC Reg. 283/88. The Commission recovers most of its costs by way of a "per gigajoule" levy assessed on each regulated utility, based on the amount of energy the utility sold in the previous calendar year (the calculation is provided below). The Insurance Corporation of British Columbia and British Columbia Transmission Corporation are billed separately for their annual regulatory costs.

The Commission also recovers proceeding costs directly from utilities for Commission expenditures attributable to public hearings and other proceedings under the *Utilities Commission Act*. Direct recoveries have varied significantly from year to year, depending on the number and duration of regulatory hearings and inquiries. Revenues are also collected from intra-provincial petroleum pipeline companies, natural gas marketers, and other utility regulatory agencies that contract with the Commission for advice and assistance.

For the reporting year the approved budget was $6,212,000; total expenditures were $6,031,155.17; revenue collected was $6,726,129.23. Excess of revenue over expenses of $694,974.06 will be returned to the regulated entities by way of the 2012 Levy.

F2011 REVENUES AND EXPENSES

Total Recoveries	$	6,726,129.23
Less: Expenditures	$	-6,031,155.17
Revenue Deferred to F2012	$	694,974.06

LEVY CALCULATION FISCAL 2011/12

The Commission's costs are expected to be recovered by a levy of $0.0083490219/GJ for the 2012 fiscal year which is an increase over the 2011 fiscal year levy from $0.0076391318/GJ. The slight increase is primarily a result expected lower energy volumes. The levy is payable by regulated entities in four quarterly instalments.

F2012 BCUC Budget (Total Budgeted Expenditures)	$	6,674,000.00
Less: F2011 Deferred Revenue (Carried Forward to F2012)		-694,974.06
Less estimated recoveries from:		
Natural Gas Marketers		-15,000.00
Intra-Provincial Oil Pipeline Companies & Upstream Gas Processors		-20,000.00
Insurance Corporation of British Columbia		-700,000.00
Expected Direct Recoveries from Public Hearings		-2,000,000.00
Net BCUC F2012 budget to be recovered through the Levy	$	3,244,025.9
Total Utility Energy Volumes sold in previous calendar year (GJ)		/ 388,551,616
	= $	0.0083490219/GJ

COMMISSION REVENUES		Amounts Recovered F2010	Amounts Recovered F2011
British Columbia Hydro and Power Authority	$	1,231,437.61	1,303,591.47
British Columbia Hydro Transmission		560,000.00	533,333.33
Cal-Gas Inc.		140.38	169.86
Central Heat Distribution Limited		9,216.43	10,177.79
Corix Multi-Utility Services Inc.			
Gas		427.79	411.77
Electric		240.63	308.83
Corporation of the City of Nelson		1,557.43	1,949.30
FortisBC Inc.		52,818.87	59,000.80
Hemlock Valley Electrical Services Limited		106.95	40.44
Insurance Corporation of British Columbia		560,000.00	533,333.33
Pacific Northern Gas (includes Granisle Grid)		44,410.09	45,427.10
Dawson Creek and Fort St. John		32,111.09	36,140.20
Tumbler Ridge		7,312.55	7,735.40
Port Alice Gas Inc.		108.37	90.53
Big White Gas Utility		260.69	331.35
Silversmith Power & Light Corporation		-	n/a
Stargas Utilities Ltd.		227.00	302.97
Sun Peaks Utilities Co., Ltd.		601.37	679.43
Terasen Gas Inc.			
Revelstoke		1,330.17	1,573.56
Lower Mainland Division		846,371.88	881,857.73
Inland Division		329,285.73	336,975.23
Columbia Division		41,582.66	41,897.63
Fort Nelson Division		5,140.17	4,750.07
Terasen Gas (Vancouver Island) Inc.		234,035.30	229,253.16
Terasen Gas (Whistler) Inc.		4,886.18	4,772.13
The Yukon Electrical Company Limited		20.05	32.35
	$	3,963,629.39	4,034,135.76
Correction to Levy Spreadsheet			0.02
			4,034,135.78

NATURAL GAS LICENCES		Amounts Recovered F2010	Amounts Recovered F2011
Access Gas Services	$	1,000.00	2,000.00
Active Energy ULC		1,000.00	1,000.00
AG Energy Co-Operative/Firefly Energy		1,000.00	1,000.00
AltaGas Ltd.		1,000.00	1,000.00
Bluestream Energy Inc.		-	2,000.00
Cascadia Energy		1,000.00	1,000.00
Connect Energy		1,000.00	1,000.00
Direct Energy		1,000.00	2,000.00
Just Energy (BC) Limited		1,000.00	1,000.00
Just Energy (formerly Universal Energy Corporation)		1,000.00	-
MX Energy		1,000.00	1,000.00
Nexen Marketing		1,000.00	1,000.00
Planet Energy Corp		1,000.00	1,000.00
Shell Energy		1,000.00	-
Smart Energy (BC) Ltd		1,000.00	1,000.00
Summitt Energy BC LP		1,000.00	1,000.00
Superior Energy		1,000.00	1,000.00
	$	16,000.00	18,000.00

INTRA-PROVINCIAL OIL PIPELINES & OTHER COMPANIES		Amounts Recovered F2010	Amounts Recovered F2011
AltaGas Ltd. – Blair Creek Gas Plant	$	1,000.00	1,000.00
Canadian Natural Resources Limited - West Stoddard Plant		1,000.00	-
Enerplus Resources - Inga Oil (F2010 and F2011)		-	2,000.00
Keyera Energy Ltd.		1,000.00	1,000.00
Trans Mountain (Jet Fuel) Inc.		1,000.00	1,000.00
Plateau Pipeline - Blueberry		1,000.00	1,000.00
Plateau Pipeline - Northeast BC & Boundary Lake		1,000.00	1,000.00
Plateau Pipeline - Sunset Prairie		1,000.00	1,000.00
Plateau Pipeline - Taylor to Dawson Creek		1,000.00	1,000.00
Plateau Pipeline - Western System		1,000.00	1,000.00
Spectra Energy - Boundary Lake		1,000.00	1,000.00
Spectra Energy - Jedney I		1,000.00	1,000.00
Spectra Energy - Jedney II		1,000.00	1,000.00
Spectra Energy - Midwinter		1,000.00	1,000.00
Spectra Energy - Peggo		1,000.00	1,000.00
Spectra Energy - Sunrise		1,000.00	1,000.00
Spectra Energy - Tooga		1,000.00	1,000.00
Spectra Energy - West Doe & Hwy Processing & Pipeline Facilities		2,000.00	2,000.00
Spectra Energy - West Doe & Hwy Transportation & Processing Facilities		1,000.00	1,000.00
	$	19,000.00	20,000.00

MISCELLANEOUS REVENUES		Amounts Recovered F2010	Amounts Recovered F2011
Recovery of Proceeding Costs from Utilities	$	2,415,562.29	2,362,558.49
Less: HST Transferred to Provincial Government			(43,972.54)
Deferred Revenue		593,137.86	335,407.52
TOTAL REVENUES	$	$7,007,329.54	$6,726,129.25
COMMISSION EXPENDITURES			
Salaries & Benefits	$	3,116,354.68	3,143,469.84
Operating Costs		1,726,675.81	1,503,650.23
Professional Services		1,828,891.53	1,384,035.10
Total Expenditures	$	6,671,922.02	6,031,155.17
Deferred Revenue Carried Forward to F2012	$		694,974.06

Summary of Decisions, Reasons for Decision and Negotiated Settlements issued in 2010/2011

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

Stave Falls Spillway Gates Replacement Project
Order G-81-10

Following the filing of BC Hydro's December 23, 2009 application for approval of capital expenditures that BC Hydro anticipated making with respect to the Stave Falls Spillway Gates Replacement Project, the Commission conducted a written public hearing to review the application. The written hearing concluded with the filing of BC Hydro's Reply Argument on April 29, 2010.

BC Hydro's Stave Falls Project has an estimated capital cost of approximately $61.5 million, to be funded entirely by BC Hydro's ratepayers. Project costs include the spillway gate design, supply and install contract, protection and control materials and installation, additional equipment and retirement items, design and design support during construction, construction management and resident engineering services, indirect BC Hydro support plus contingency, inflation, interest during construction and capital overhead.

The Commission determined that the expenditures for the Project, as described in the application, are in the public interest in accordance with section 44.2(3)(a) of the *Utilities Commission Act*.

BC Hydro is required to report on the following:

- Quarterly progress reports on the Project schedule, costs and any variances or difficulties that the Project may be encountering. The quarterly progress reports will be filed within 30 days of the end of each reporting period.
- A final report within six months of the end or substantial completion of the Project. The final report is to include a complete breakdown of the final costs of the Project, a comparison of these costs to the Project Expected Cost estimate and provide an explanation of all material cost variances.

Large General Service Rate
Order G-110-10

BC Hydro applied to amend the rates for customers taking service under Rate Schedules 1200, 1201, 1210 and 1211, for customers falling under the Existing Large General Service class of customers, on October 16, 2009. In its application, BC Hydro proposed splitting the existing Large General Service class into two classes: the Large General Service class and the Medium General Service class. There are approximately 23,000 accounts in the existing Large General Service class, although many customers have more than one account. The new Large General Service class would include those accounts with monthly peak demand of 150 kW or more, while those with monthly peak demand between 35 kW and 150

kW would fall in the new Medium General Service class. There would be about 5,000 Large General Service accounts and 18,000 Medium General Service accounts.

The application was reviewed through the Commission's Negotiated Settlement Process in March and April 2010. On May 14, 2010 a proposed Settlement Agreement (supported by all participants except for a single party, the British Columbia Sustainable Energy Association/Sierra Club of British Columbia *et al.*) was released. The Commission Panel approved the Negotiated Settlement Agreement on June 29, 2010.

The general intent of the Negotiated Settlement Agreement is to maximize cost-effective customer efficiency and conservation incentives while minimizing unintended consequences to BC Hydro.

The purpose of the rate design amendment is to encourage energy conservation. Other highlights of the Negotiated Settlement Agreement include:

- a two-part rate structure to signal the long-run marginal cost of new electricity supply, among other things;
- an inverted rate structure such that consumption above a certain amount will be charged at a higher rate (up to the upper band limit);
- the calculation of historical baselines based on a three year rolling average with a provision for growth adjustment in situations involving a large increase in consumption of 30 percent or more in a given year; and
- the ability of a customer to apply to the Commission to seek an increase in its historical baseline in circumstances where it expects a significant, permanent increase in energy consumption due to a significant capital investment in plant.

Reporting requirements:

- Within 36 months of the implementation date of January 1, 2011, BC Hydro will file a report that addresses the issues as outlined in Paragraph 16 of the Negotiated Settlement Agreement.
- BC Hydro is to demonstrate its compliance with section 58.1(6) and clarify its position on overall class revenue neutrality in its annual Cost of Service report to the Commission.

Transmission Service Rate – Customer Baseline Load 2009 and 2010 Dispute with Buckeye Canada
Order G-139-10

Buckeye Canada filed an objection to BC Hydro's strict application of the Customer Baseline Load (CBL) Tariff Practices' facility shutdown threshold during the recession, stating it posed a particular hardship on smaller operations. Buckeye also appealed BC Hydro's termination of its persistence allowance (a CBL credit over the lesser of the life of the demand-side management project or ten years). On February 16, 2010, Buckeye informed the Commission that it has been unable to reach a settlement with BC Hydro on its CBL adjustment and requested the Commission resolve the disputes.

The disputes were reviewed through a written process that concluded with the Reply Submission from Buckeye on June 11, 2010.

The Commission reviewed the submissions from the parties and determined that BC Hydro is to credit Buckeye's 2010 Interim CBL for a total of 4,000,000 kWh. BC Hydro is to review Tariff Supplement No. 74 Customer Baseline Load Determination Guidelines and the CBL Adjustment Tariff Practices and propose amendments to address the following issues:

- Production stoppages which accumulate to the lesser of 5 percent of CBL or 10 GWh but do not occur as discrete events; and
- Outside market events which cause businesses to reduce energy use involuntarily.

Hugh Keenleyside Spillway Project
Order G-177-10

The Hugh Keenleyside Dam, completed in 1968, is located on the Columbia River about eight kilometres upstream of Castlegar. Following an assessment of the Dam spillway gates system, BC Hydro determined the level of reliability of the gates is not sufficient to ensure reliable passage of water in a flood event or post-earthquake reservoir drawdown. On July 16, 2010, BC Hydro presented the Commission with a proposal to address the identified deficiencies and significantly reduce the risk of downstream loss of life, property and environmental damage associated with a failure of the existing spillgate systems.

The Project has an expected capital cost of $90.2 million and authorized capital cost of $102.0 million. The Project involves the refurbishment of four spillway gates and eight low level outlet gates at Hugh Keenleyside Dam with a target completion date in December 2013.

On July 16, 2010, the Commission accepted BC Hydro's application as being reasonable and consistent with good engineering practice to reduce the risks associated with a spillgate system failure and determined the proposed expenditures as outlined in the application to be in the public interest.

2011 Revenue Requirements Negotiated Settlement
Order to G-180-10

BC Hydro's March 3, 2010 Revenue Requirements application applied for, among other things, approval of an across-the-board rate increase of 6.11 percent, and approval to increase the Deferral Account Rate Rider from 1 percent to 4 percent, both effective April 1, 2010. A Negotiated Settlement Process was conducted for this application.

On November 19, 2010, a proposed settlement package for the application was circulated to the Commission and all parties who intervened in the process. The package included the Negotiated Settlement Agreement, along with a number of Letters of Comment in support of the Agreement and two letters opposing it.

The Commission Panel approved the Negotiated Settlement Agreement and was satisfied that it represented a fair settlement considering the circumstances; rates that are fair, just and reasonable and not unduly discriminatory or preferential; and therefore an Agreement that was in the public interest.

Open Access Transmission Tariff Amendments - Reasons for Decision
Order G-192-10

BC Hydro's September 16, 2010 application requested approval to amend the Open Access Transmission Tariff (OATT) to reflect the integration of BC Hydro and BCTC under the *Clean Energy Act*, S.B.C. 2010, c. 16. The application also sought an order granting BC Hydro relief from compliance with the terms of Attachment K (Transmission Planning Process) to BC Hydro's OATT until January 1, 2012. Such relief would allow BC Hydro to fully assess its transmission planning process and determine how it will proceed with compliance to the *Clean Energy Act* in conjunction with the *Utilities Commission Act* and the OATT. BC Hydro submitted revisions to its application on November 9, 2010.

The application was reviewed through a written comment process, which concluded in November 22, 2010.

In its Reasons for Decision the Commission approved the amended application's proposed OATT amendments, the cancellation of certain OATT rate schedules, and the request for relief regarding the obligations under Attachment K (Transmission Planning Process) of the OATT until January 1, 2012. In addition, the Commission found the following:

- Rate Schedules 00 to 10, and Tariff Supplements 78, 79 and 80 (formerly known as Tariff Supplements 1, 2 and 3) were approved and came into effect on December 9, 2010.
- Rate Schedules 100 to 110 (of the Transmission Provider) and Rate Schedules 3000 to 3002 (of the Transmission Owner) were cancelled.
- BC Hydro Rate Schedules 3011 to 3016 and BC Hydro Tariff Supplement 69 were cancelled.

Reconsideration Regarding Order G-103-09, as Confirmed by Letter L-95-09, Concerning British Columbia Transmission Corporation Firm Transmission Sales to Alberta
Order G-45-10

BC Hydro applied for reconsideration of Commission Order G-103-09, asking for reinstatement, effective April 1, 2010, of the 25 MW of Long Term Firm Point to Point capacity on the BC to Alberta path which it lost to Cargill Limited (Cargill) as a result of Order G-103-09. An unanticipated effect of cancelling those specific contracts as opposed to reinstating the status quo immediately prior to December 1, 2007 was a reallocation of 25 MW of capacity from BC Hydro to Cargill, a result that was not intended by the Commission Panel.

The application for reconsideration was filed on November 26, 2009 and was supported by three intervener organizations representing three major customer groups in the province: the British Columbia Old Age Pensioners' Organization *et al.*, the Commercial Energy Consumers Association of British Columbia and the Joint Industry Electricity Steering Committee.

The only party to oppose the application was Cargill, the beneficiary of the Order.

The Commission Panel accepted the application and varied Order G-103-09 to reverse the reallocation of capacity as it unfairly deprived BC Hydro of 25 MW of capacity. The inequity to BC Hydro from the loss of its capacity was deemed to be greater than the marginal benefit of the additional transparency provided by the inclusion of the subject clause on certain contracts.

Vancouver City Central Transmission Project and VCCT Substation Distribution Assets
Order C-3-10

The Commission granted a Certificate of Public Convenience and Necessity to BCTC for the Vancouver City Central Transmission (VCCT) Project and a further CPCN was granted to BC Hydro for the construction of the VCCT Substation Distribution Assets, as applied-for in the September 21, 2009 CPCN application to construct and operate the VCCT Project.

The VCCT Project is BCTC's preferred solution to:

i) serve load growth in the Mount Pleasant/South False Creek area;

ii) resolve reliability concerns associated with the end of life condition of the Main Street distribution duct banks being used to serve the Mount Pleasant/South False Creek area; and

iii) resolve reliability concerns in view of the zero-rating of transmission circuit 2L53.

BCTC filed amendments to its application on October 21, 2009, to request a CPCN for the construction and operation of the VCCT Substation Distribution Assets. The application was reviewed through a written public hearing process.

The Commission Panel reviewed the evidence and submissions of all of the parties and determined that the Project was in the public interest.

Columbia Valley Transmission Project Certificate of Public Convenience and Necessity
Order C-5-10

On January 22, 2010, BCTC applied for a CPCN to construct and operate the Columbia Valley Transmission Project. BCTC proposed the Project in order to meet the immediate load growth as well as load growth forecast over a 30-year period in the upper Columbia Valley region. The application was reviewed through a written public hearing process.

The Commission Panel granted a CPCN to BC Hydro for the Project after considering the evidence and arguments of all parties. The Panel concluded that the Project is necessary to reliably serve BCTC's load in the upper Columbia Valley and that it is in the public interest because it is the most cost-effective long-term solution. Public consultation and First Nations consultation was found to be adequate.

Reporting requirements:

- Quarterly progress reports on the Project are to show planned versus actual schedule, planned versus actual costs, and any variances or difficulties BC Hydro may encounter in implementing the Project. The quarterly progress reports are to be filed within 30 days of the end of each reporting period.
- A Final Report, within six months of the end or substantial completion of the Project, that provides a complete breakdown of the final costs of the Project, compares these costs to the cost estimate, and provides a detailed explanation and justification of all material cost variances.

Reconsideration of G-139-10 Transmission Service Rate – Customer Baseline Load 2009 and 2010 Dispute with Buckeye Canada
Order G-4-11

On October 15, 2010, BC Hydro applied for a reconsideration and variance of Order G-139-10 issued on September 7, 2010. In Order G-139-10 the Commission granted a portion of the relief sought by Buckeye Canada, a BC Hydro Transmission Service Rate customer, by way of directing an upward adjustment to its Customer Baseline Load, which was the subject of a dispute between the parties.

BC Hydro submitted the Commission made the following errors:

1. The Commission's decision to grant relief to Buckeye went against the objectives of the tariff and did not encourage electricity conservation and efficiency of use;
2. The Commission erred in suggesting that it was relevant whether the customer's shutdowns were due to the economic recession or simply an ordinary operational management decision; and
3. The Commission Panel made its Decision despite its conclusion that it had insufficient evidence before it to make pertinent findings of fact.

BC Hydro and Buckeye each filed submissions regarding the Reconsideration application. After review of the submissions, the Commission Panel denied BC Hydro's request for reconsideration and variance of Order G-139-10.

Residential Inclining Block Re-Pricing
Order G-45-11

On December 21, 2010 BC Hydro filed its Residential Inclining Block (RIB) Rate Re-pricing application with the Commission under sections 58 to 61 of the *Utilities Commission Act*. In its application, BC Hydro sought approval of a pricing principle under which BC Hydro would increase all three components of the residential rates (Step-1 energy rate, Step-2 energy rate and Basic Charge) by the amount of any approved general rate increase. The application also discussed an alternate pricing principle based on employing the class average rate change plus 10 percent as a bill impact threshold.

The application was reviewed through a written public hearing process. Five Interveners filed Final Submissions with alternative proposals provided in two of those submissions.

While BC Hydro modeled two proposals for the 2011 to 2018 period it acknowledged uncertainty regarding the long run marginal cost over that period. Due to the uncertainty surrounding the level of the long run marginal cost and the limited scope of the application, the Commission Panel concluded the following:

- BC Hydro will increase the Step-2 energy rate up to the higher of the class average rate change or 10 percent bill impact effective April 1, 2011, subject to the Step-1 rate increasing by no less than the annual rate of inflation. The Step-1 rate will be calculated residually but should always be increased by no less than the annual rate of inflation. The Basic Charge is to be increased at the rate of general rate increase.
- This RIB rate pricing principle will apply only for BC Hydro's fiscal 2012 to 2014 periods inclusive to allow for a broader future review of this important policy.
- BC Hydro shall file a more comprehensive RIB rate application on or before December 1, 2013 and include within that application the specific information requested in the Reasons for Decision (attached to Order G-45-11) to allow the Commission to determine whether a new RIB rate pricing principle should be implemented effective April 1, 2014.

Sinixt Nation - Reconsideration of Order G-12-10 BC Hydro Waneta Transaction Order G-126-10

On April 13, 2010, the Sinixt Nation (Sinixt) applied for reconsideration of Order G-12-10 which set out the findings of the Commission with respect to the application by BC Hydro for the acquisition of a one-third interest in the Waneta Dam from Teck Metals Ltd. The acquisition required an $825 million payment to Teck plus transaction costs estimated at $25 million. The Commission had ruled that that the expenditures were in the public interest. The Sinixt asserted the Commission made errors of fact and/or law in determining that the consultation undertaken by BC Hydro was adequate to uphold the honour of the Crown.

A written comment process was established for Phase One of the Reconsideration on the Sinixt's application.

The application for reconsideration was denied as the Commission Panel found that criteria for advancement to the second phase of the reconsideration application were not met by the submissions of any of the Sinixt, the Okanagan Nation Alliance, or the Ktunaxa Nation Council.

BRITISH COLUMBIA TRANSMISSION CORPORATION

Merged with British Columbia Hydro and Power Authority on July 1, 2010
pursuant to the Clean Energy Act

2011 Capital Plan Update
Order G-87-10

BCTC's January 8, 2010 - 2011 Capital Plan Update requested adjustments to its 2010 and 2011 Transmission System Capital Plan previously approved by Commission Order G-87-09. The Update requested acceptance of the expenditure schedules identified in the 2011 Capital Plan Update as meeting the requirements of section 45(6) of the *Utilities Commission Act*.

The Plan was reviewed through a written public hearing process, established by Order G-9-10 dated January 14, 2010. The Commission Panel considered the application, evidence and submissions of Interveners and the Applicant, as well as the Court of Appeal decisions in *Carrier Sekani Tribal Council v. British Columbia (Utilities Commission) 2009 BCCA 67* and *Kwikwetlem First Nation v. British Columbia (Utilities Commission) 2009 BCCA 68*.

The Panel's Reasons for Decision, issued on June 2, 2010, determined that the 2010 Capital Plan met the requirements of section 45(6) of the Act. The following expenditure schedules, for reasons set out in the Reasons for Decision were accepted: the Growth Capital Projects as listed in Appendix B of the Order; and the Sustaining Capital expenditure for PCB Oil Spill Containment of $5 million. The Commission rejected the following expenditure schedules, for reasons set out in the Reasons for Decision: the Dawson Creek-Chetwynd Area Remedial Action Scheme, and the BCTC Capital expenditures for the enterprise Project Portfolio Management Project.

Certificate of Public Convenience and Necessity for the Vancouver City Central Transmission Project
Order C-3-10

On September 21, 2009, BCTC applied for a Certificate of Public Convenience and Necessity to construct and operate the Vancouver City Central Transmission Project. The proposed Project is comprised of a 200 MVA indoor substation and two underground 230 kV transmission circuits.

The forecast project-cost for the transmission assets for the Project is $174 million, plus an additional $27 million for Substation Distribution Assets (which were not the subject of this application). The estimated total Project cost including both transmission assets and Substation Distribution Assets is $201 million. The new substation should be in service by June 2012.

The impact of the Project on the Transmission Revenue Requirement is forecast to be $17.5 million per year or 2.96 percent. The impact of the Vancouver City Centre Transmission Project on the BC Hydro Revenue Requirement including both the Transmission and SDA components is estimated to be $24.4 million per year or 0.80 percent of the BC Hydro Revenue Requirement.

The application was reviewed by way of a written public hearing process that concluded with the filing of BCTC's Reply Argument on April 15, 2010.

Following a review of the evidence and submissions of all of the parties the Commission Panel issued its Decision on June 2, 2010, ruling that the Project is in the public interest. A CPCN was granted to BCTC for the Vancouver City Central Transmission Project. A further CPCN was granted to BC Hydro for the construction of the Substation Distribution Assets.

Reporting requirement:

- Quarterly reports providing information on project status, cost, schedule and risks.

2010 Transmission Revenue Requirement and Rate Change
Order G-135-10

The Commission Panel approved BCTC's March 4, 2010 Transmission Revenue Requirement (TRR) and Rate Change application requesting approval of its 2011 Rates under sections 59 to 61 of the *Utilities Commission Act* for permanent rates effective April 1, 2010, with minor modifications.

The following components of the 2011 Transmission Revenue Requirement were approved:

a) The forecast for Generation Related Transmission Assets and Substation Distribution Assets non-tariff revenues;

b) The inclusion of the forecast capital plant in-service in the BC Hydro Owners Revenue Requirement as further directed;

c) The forecast Asset Management and Maintenance Revenue Requirement and BCTC Revenue Requirement, including the revised Return on Deemed Equity to be recalculated as further directed; and

d) The Point-to-Point Transmission Services Revenue Forecast.

The Commission Panel rescinded Directive No. 2 in Order G-108-10, which had established a deferral account to capture the impact of the six capital projects on the TRR. The Panel ordered that the BC Hydro Owners Revenue Requirement included in the final 2011 TRR should reflect removal of the Dawson Creek – Chetwynd Area Remedial Action Scheme project and the corrections made in BCTC's responses to Commission Information Requests 1.5.12 and 1.5.13.

As a result of the transfer of BCTC's responsibilities to BC Hydro under the *Clean Energy Act*, BC Hydro was ordered to file a recalculation of the Return on Deemed Equity. This revised figure will be used to calculate the final Transmission Rates.

The application was reviewed through a written regulatory review process, concluding on July 16, 2010 with the filing of BC Hydro's Reply Submission.

Inquiry into British Columbia's Long-Term Transmission Infrastructure
Order G-98-10

On December 11, 2008, the Minister of Energy, Mines and Petroleum Resources issued Terms of Reference for the Commission's Inquiry to make determinations with respect to British Columbia's infrastructure and capacity needs for electricity transmission for the period ending 20 years after the day the Inquiry begins. Following the Government's consideration and policy responses to the recommendations of the Green Energy Advisory Task Force, the Minister advised that amended terms of reference for the Inquiry were required, and that it would not be productive to continue with the Inquiry before May 31, 2010. The Commission Panel subsequently suspended the Inquiry until May 31, 2010.

The *Clean Energy Act* (Bill 17, 2010), introduced in the Legislature on April 28, 2010, proposed the reintegration of BCTC with British Columbia Hydro and Power Authority (BC Hydro) and also proposed certain consequential amendments to the *Utilities Commission Act*.

The *Clean Energy Act* received Royal Assent on June 3, 2010, resulting in the repeal of sections 5(4) to (9) of the *Utilities Commission Act*. This removed the legislated requirement for the Commission to hold an Inquiry.

On June 4, 2010 the Commission Panel issued Order G-98-10 cancelling the Inquiry in accordance with the *Clean Energy Act*.

Reconsideration of Order C-4-08 Interior to Lower Mainland Transmission Project
Order G-15-11

On August 5, 2008, the Commission granted a Certificate of Public Convenience and Necessity to the BCTC for the Interior to Lower Mainland Transmission Project. During that Proceeding, the Commission decided that it need not consider the adequacy of First Nations consultation and accommodation efforts on the ILM Project. Kwikwetlem First Nation appealed that decision to the British Columbia Court of Appeal. On February 18, 2009, the Court of Appeal issued its decision in *Kwikwetlem First Nation* v. *British Columbia (Utilities Commission)* 2009 BCCA 68. The Court suspended the CPCN and directed the Commission to reconsider First Nations consultation and to determine whether the Crown's duty to consult and accommodate First Nations had been met up to August 5, 2008, the date the CPCN was granted.

Aboriginal rights and title are constitutionally protected by section 35 of the *Constitution Act, 1982*. The Crown has an obligation to consult meaningfully with First Nations when its action may adversely affect those rights. The ILM Project has this potential. BCTC, as the project proponent, delegated the consultation responsibility to BC Hydro but remained involved in some consultation activities.

The Commission Panel considered the evidence and found the Crown's consultation was not adequate for certain First Nations.

The Commission Panel examined the specific facts relating to each individual First Nation Intervener and found consultation with the following First Nation Interveners was inadequate to August 5, 2008: Upper Nicola Indian Band; Coldwater Indian Band; Cook's Ferry Indian Band; Nlaka'pamux Nation Tribal Council; Spuzzum First Nation; Boothroyd Indian Band; Skuppah Indian Band; Lytton First Nation; Oregon Jack Creek Band; Stó:lō Tribal Council; Shxw'ow'hamel First Nation; Cheam First Nation; and Seabird Island First Nation.

The Commission Panel found BC Hydro/BCTC's consultation with the following First Nation Interveners was adequate to August 5, 2008: Okanagan Nation Alliance; Kanaka Bar Indian Band; Kwaw-kwaw-a-pilt First Nation; Soowahlie First Nation; Sumas First Nation; and the Hwlitsum First Nation.

The Commission examined the relief sought by the Interveners, BCTC and BC Hydro, and determined that maintaining the suspension of the CPCN would allow BC Hydro an opportunity to remedy the deficiencies identified. Accordingly, the CPCN remains suspended.

The Commission Panel directed BC Hydro to remedy the specific deficiencies identified and report back to the Commission as required.

Reporting requirements:

- A compliance report, containing a comprehensive and detailed description of its consultation in respect of the directives, within 120 days from the date of the Order. The First Nation Interveners for whom consultation was found to be inadequate had 21 days from the date of the filing of the report to file a written response to the report, and BC Hydro then had 7 days from the date of the filing of the First Nation Interveners' responses to file a written reply to the responses. The Commission is to review the submissions and, if the deficiencies in consultation have been remedied to the Commission's satisfaction, will lift the suspension of the CPCN.
- Quarterly Progress Reports that include detailed reporting on First Nations consultation similar to the Revelstoke Unit 5 Project Quarterly Progress Reports.
- Provided the CPCN suspension is lifted, a Final Report is to include a comprehensive and detailed report on the consultation with First Nations.

FORTISBC INC.

2009 Rate Design Cost of Service Analysis
Order G-156-10

On October 30, 2009, FortisBC submitted an application related to rate design. The application included results of a 2009 Cost of Service Analysis and proposals to revise Rate Schedules of selected customer classes and general revisions to other tariff sheets. Zellstoff Celgar Limited Partnership (Celgar) used the application proceeding to request the Commission establish a Generation Baseline between it and FortisBC. Several areas were examined extensively through the proceedings including: the Cost of Service Analysis; Celgar's request for a Generation Baseline; rate structures; rate rebalancing; and Terms and Conditions of FortisBC's Electric Tariff.

In assessing FortisBC's proposed Cost of Service Analysis the Commission Panel made the following key determinations:

- actual coincident peak demands should be used for all customers for Cost of Service Analysis purposes rather than contract demands or demand limits;
- FortisBC's use of the two coincident peak allocator method for allocating the demand portion of production and transmission costs was accepted;
- FortisBC was directed to rerun and submit the Cost of Service Analysis with a single class for Wholesale customers except for Nelson, with Celgar taking service during the test year on Rate Schedule 31, and using amended load factors for the Irrigation customers, all within 30 days of the Order.

In respect of Celgar's request for a Generation Baseline, the Panel found that:

- Celgar's request was prohibited by Commission Order G-48-09; and
- the Commission Panel declined to set a Generation Baseline between Celgar and FortisBC.

In support of recent BC policy and legislative developments which strongly highlight energy efficiency and conservation the Commission Panel made the following determinations and directed FortisBC to:

- develop a plan for introducing residential inclining block rates incorporating a lower Basic Charge in the immediate future, and to file a residential inclining block application with the Commission no later than March 31, 2011;
- initiate consultations with Industrial customers with the goal of introducing a stepped rate for transmission service similar to Rate Schedule 1823 of BC Hydro; and
- ensure the billing determinants for Wholesale customers are consistent with those for Large General Service Transmission customers.

The Commission Panel made the following determinations regarding the proposed rebalancing of rates amongst rate classes:

- FortisBC's range of reasonableness of revenue-to-cost ratios of 95 percent to 105 percent was approved;
- The appropriate target for revenue-to-cost ratios in each customer class is unity or one, and rebalancing should only be required when a customer class falls outside the range of reasonableness;
- FortisBC was directed to adjust its rates with the goal of achieving revenue-to-cost ratios of unity for each class; and
- FortisBC was directed to undertake load research to establish the load characteristics of the Irrigation class. Until FortisBC is better able to demonstrate the load characteristics of the Irrigation class, the Irrigation class is exempt from rate rebalancing and is subject only to base adjustments associated with FortisBC's revenue requirement and BC Hydro flow-through.

The Commission Panel ruled in favour of Intefor's claim that Celgar's requirement for Interfor's security deposit was discriminatory because FortisBC's policy has been applied inconsistently and in a preferential manner. The Panel directed FortisBC to: develop a new policy that demonstrates the management of credit risk through an active monitoring of credit worthiness and which is non-discriminatory in nature; and return the security deposit in respect of Interfor.

2011 Revenue Requirements Negotiated Settlement
Order G-184-10

The Performance Based Regulation Settlement approved by Commission Order G-58-06 requires FortisBC to hold an Annual Review, Workshop and Negotiated Settlement Process each November with a goal of achieving firm rates by December 1 for the following year. The Annual Review compares the Company's actual performance for the year to the approved targets for the Performance Standards to determine whether the Company is entitled to an incentive payment. The Revenue Requirements Workshop focuses on future test periods and the Negotiated Settlement Process is conducted to establish rates for the following year.

On October 1, 2010, FortisBC filed its Preliminary 2011 Revenue Requirements, seeking a 5.9 percent general rate increase effective January 1, 2011. The 2010 Annual Review and 2011 Revenue Requirements Workshop were held on November 16, 2010 in Kelowna, BC, followed by a Negotiated Settlement Process on November 17, 2010. The resulting Settlement Agreement for a general rate increase of 5.2 percent effective January 1, 2011, Terms of Settlement and financial schedules showing the effect of changes arising from the Agreement were subsequently approved by the Commission.

2011 Capital Expenditures Plan
Order G-195-10

FortisBC's 2011 Capital Expenditure Plan sought approval for expenditures associated with new capital projects totalling $67.6 million, consisting of $66.2 million in 2011 and a further $1.5 million in 2012 for the completion of projects that will begin in 2011. This total included a $5.764 million provision for Demand Side Management programs. The entire 2011 Capital Expenditure Plan consists of $103.3 million in 2011 and a further $5.3 million in 2012, including projects previously accepted or approved by the Commission.

In its review of the application the Commission Panel noted that 2011 is a transition year in FortisBC's planning process, and reviewed both the Capital Expenditure Plan and Demand Side Management Plan in that context. Some of the factors cited by Panel include:

- The major medium-term projects identified in the previous 2005-2024 System Development Plan will mostly have been completed by the end of 2011. The next Integrated System Plan, to be completed and filed in 2011, will outline a twenty-year horizon of planned future investment spending on FortisBC system assets.
- The 2009 filing by FortisBC of its Long-Term Resource Plan, and the subsequent evidentiary update pursuant to section 44.1 of the *Act*.
- FortisBC's intention to file an application in 2011 for the installation of an Advanced Metering Infrastructure.
- 2011 is an extension and the final year of the 2006 Performance Based Rate Settlement which FortisBC operates under.
- Recognition of the new era introduced by the passing of the *Clean Energy Act*.

After reviewing the projects and addressing concerns, the Commission Panel rejected a total of $14.241 million from the applied for capital expenditures. The remaining capital expenditures of $53.385 million in 2011 and 2012 are considered to be in the public interest under section 44.2(3)(a) and meet the requirements of section 45(6) of the *Utilities Commission Act*.

Cost of Service Analysis Re-Filing Pursuant to Order G-156-10
Order G-196-10

By letter dated November 19, 2010 FortisBC, in accordance with Directive 3 of Commission Order G-156-10, filed a Cost of Service Analysis Update, together with a summary of the resulting Revenue-to-Cost ratios.

By December 9, 2010, the Commission received comments from British Columbia Municipal Electrical Utilities, British Columbia Old Age Pensioners' Organization *et al.*, Big White Ski Resort, Irrigation Ratepayers Group, Rate 30 Customer Group, Mr. Andy Shadrack, and Zellstoff Celgar Limited Partnership, and reply comments from FortisBC.

After reviewing the Cost of Service Analysis and the evidence the Commission Panel made the following rulings:

- Fortis BC was directed to correct two anomalies in the filing, regarding the group coincidence factor for lighting, and the months to be used in applying a load factor to its Irrigation class customer;
- The Commission Panel directed FortisBC to re-run the Cost of Service Analysis using 8,000 kVA rather than 12,000 kVA as the value for Celgar's demand and to adjust the Rate Schedule 31 revenue accordingly.

The Panel did not find sufficient evidence to support Celgar's claim for relief, or to make a finding on their complaint concerning FortisBC's transmission service ancillary services tariffs.

Reporting requirements:

- On or before January 31, 2012 a report setting out FortisBC's peaks for each month of the year together with Celgar's monthly coincident and non-coincident peaks.

Zellstoff Celgar Limited Partnership Reconsideration of Order G-156-10
Order G-3-11

Celgar's December 3, 2010 application for reconsideration and variance of Order G-156-10 and the accompanying Decision dated October 19, 2010 for FortisBC's 2009 Rate Design and Cost of Service Analysis, requested:

i. that the Decision and Order be reconsidered and varied to enable Celgar's request for adequate, just and reasonable service between it and FortisBC utilizing service from FortisBC, whether utilizing a Generation Baseline or otherwise; and

ii. in particular, that FortisBC be directed to provide service at embedded cost or rolled in rates in a manner that does not contravene Order G-48-09 and complies with the *Utilities Commission Act*.

Celgar asserted:

i. that the Commission's prescription that Celgar take service from FortisBC under Rate Schedule 31 is unjust and unduly discriminatory and subjects Celgar to undue prejudice or disadvantage; and

ii. that at page 97 of the Decision the Commission erred in its assessment of whether or not there was a benefit from the establishment of a Generation Baseline and increased power purchases from Celgar thereunder.

The Commission Panel determined that the criteria for advancement to the second phase of reconsideration had not been met by the submissions of Celgar. The application was denied.

INSURANCE CORPORATION OF BRITISH COLUMBIA

Regional Claim Centres Financial Allocation and Specified Financial Allocation Functions – A Filing on the Report on Findings from the Independent Third Party
Order G-75-10

On November 26, 2009, Navigant Consulting Inc. filed its "Report on Findings from the Independent Third Party Review of ICBC's Regional Claim Centres Financial Allocation and Specified Financial Allocation Functions". Navigant provided several recommendations in its Independent Third Party Report, including the need for a more detailed study in the near future to determine work effort percentages.

Navigant was the Independent Third Party selected following the Expression of Interest issued by ICBC. The report followed the Revised Terms of Reference dated February 20, 2009 as approved by Order G-31-09.

Following the written review process, which concluded on January 29, 2010 with the filing of ICBC's reply submission, the Commission was satisfied the cost allocation methodology appropriately allocates costs to Basic Insurance and Optional Insurance. The Commission agreed with both Navigant and ICBC that further work is required to undertake a detailed cost allocation study and accepts the time line proposed by ICBC to complete the detailed work effort study with the Commission by summer 2011.

The Commission directed ICBC to undertake and file a detailed work effort study by September 1, 2011 and to include a report from the independent third party reviewer. The Independent Third Party is to be involved throughout the planning stage of the detailed study, and during the study group meetings to finalize work effort and proxy allocations. Thereafter, an update of the detailed study is to be filed within 24 months of a Commission Decision on that filing. In addition, another detailed study is to be filed when significant business changes occur or, at minimum, within 5 years from September 1, 2011.

Streamlined Regulatory Process Application
Order G-65-10

The Commission assumed jurisdiction over ICBC's Basic Insurance rates and services in 2003. In its May 12, 2009 application, ICBC submits that the framework for the regulation of Basic Insurance rates has been established and the elements involved in the determination of Basic Insurance rates have been subjected to rigorous examination in several Commission proceedings. ICBC believes that it is appropriate to propose a more efficient and effective regulatory process for Basic Insurance revenue requirements applications. The proposed process involves public participation and ICBC believes that it is transparent and credible and involves an appropriate level of regulatory oversight.

ICBC applied for an order specifying the form and content of, and review process for, ICBC's universal compulsory automobile insurance revenue requirements applications meeting specified criteria. The application was reviewed through a written hearing process that concluded on March 17, 2010.

The Commission is satisfied that the proposed Streamlining process in the revised application, together with the directions and modifications identified in the Panel's Reasons, will result in a more efficient review and approval of ICBC's revenue requirement applications, while at the same time ensuring the Commission remains informed of ICBC's financial condition. The streamlined regulatory process is expected to be efficient, adequate and transparent for dealing with small rate change indications.

The Commission Panel accepted as reasonable ICBC's proposals to file a full revenue requirements application by 2012 and a review of the streamlined regulatory process within five years from the date of the Order approving the revised application. The Panel approved the Streamlined Regulatory Process as modified by the directives contained in the Reasons for Decision.

With respect to the filing of an Actual Certificate when no rate increase is requested, the Panel directed ICBC to include Actuarial Rate Indication Analysis; the summarized operating expenses as required in Section 3.3; and the investment performance information as required in Section 3.4 of the Reasons for Decision. The additional information will be filed for information purposes only and no further process will occur unless initiated by the Commission.

Changes to Universal Compulsory Automobile Insurance for Fleetplan Vehicles
Order G-115-10

ICBC applied on January 28, 2010, seeking three changes to its Fleetplan insurance program:

i. Revised eligibility criteria for fleet status for all new fleets.

ii. Standardised Basic insurance premiums for commercial and non-commercial trailers, and associated reduction in Basic insurance base rates for all trailers.

iii. Elimination of Fleet Retrospective Rating Program Plan "A".

The three requested approvals are independent of each other and intended to be revenue neutral. The Commission's written hearing process concluded following receipt of ICBC's reply argument on April 30, 2010.

After considering the application, the information requests and related responses, the Final Submissions, and ICBC's Reply Arguments, the Commission made the following determinations:

- The Commission approved the proposed change to Fleetplan eligibility criteria noting that there must be a minimum vehicle threshold to qualify for fleet status. The ICBC proposal of changing the threshold from five total vehicles to five motor vehicles was not opposed by Interveners, and therefore accepted by the Commission.
- The Commission denied the proposed standardisation of trailer Basic insurance premiums. The Panel found that the standardisation proposal involves premium dislocations, which are disadvantageous for safe fleet operators and advantageous for poor safety records, and therefore inconsistent with Special Direction IC2.
- However, the Commission believes that the general intent of the standardisation proposal is desirable, and encourages ICBC to re-examine whether an implementation which limits total annual premium increases may be feasible.

The Commission approved the proposed elimination of Fleetplan Retrospective Program Plan "A". Eliminating Plan "A" does not increase premiums for operators with good safety records, who can realise premium benefits by switching to Plan "B". Customers are not compelled to remain within the Retrospective Program. The potential Plan "B" premium surcharges of up to 10 percent may be avoided by opting out of the Retrospective Program. Participation in the Retrospective Program is not essential to realizing some degree of discount. Those customers maintaining good loss experience, and those improving their loss experience, realise premium rewards whether or not they participate in the Retrospective Program. The proposed amendment to the Retrospective Rating program is consistent with government policy, as it still provides rewards for operators who improve their safety performance.

2010 Revenue Requirements
Order G-137-10

On May 31, 2010, the ICBC filed an application under the Streamlined Revenue Requirements process as established in Commission Decision G-65-10, requesting approval for:

- a decrease in universal compulsory automobile insurance rates (Basic Insurance) rates of 1.9 percent for all new or renewal policies with an effective date on and after November 1, 2010 (Policy Year 2010);
- a plan to address Basic Insurance capital in excess of 150 percent of the Minimum Capital Test in response to the Commission directive in Order G-65-10; and
- changes to the Marketing and Broker Services Allocation.

The Commission Panel ordered a decrease in Basic Insurance rates of 2.4 percent, 0.5 percent more than the 1.9 percent requested in the application. The Panel accepted ICBC's plan addressing excess Basic Insurance capital and approved the Marketing and Broker Services Allocation requests.

Decrease in Basic Insurance Rates of 1.9 Percent

On May 31, 2010, the ICBC filed an application under the Streamlined Revenue Requirements process as established in Commission Decision G-65-10, requesting approval for:

- a decrease in universal compulsory automobile insurance rates (Basic Insurance) rates of 1.9 percent for all new or renewal policies with an effective date on and after November 1, 2010 (Policy Year 2010);
- a plan to address Basic Insurance capital in excess of 150 percent of the Minimum Capital Test in response to the Commission directive in Order G-65-10; and
- changes to the Marketing and Broker Services Allocation.

The Commission Panel ordered a decrease in Basic Insurance rates of 2.4 percent, 0.5 percent more than the 1.9 percent requested in the application. The Panel accepted ICBC's plan addressing excess Basic Insurance capital and approved the Marketing and Broker Services Allocation requests.

PACIFIC NORTHERN GAS LTD./PACIFIC NORTHERN GAS (N.E.) LTD.

Pacific Northern Gas Ltd./Pacific Northern Gas (N.E.) Ltd.
Capital Structure and Equity Risk Premium
Order G-84-10

By letter dated July 16, 2009, PNG-West and PNG (N.E.) (collectively PNG) filed an application for Capital Structure and Equity Risk Premium (CAP/ROE application). Specifically, PNG applied to have the common equity ratio for the PNG-West Division established at 47.5 percent and to have the common equity ratios for both divisions of PNG (N.E.) set at 42.5 percent. PNG also applied to have the rates of return on common equity set at 75 basis points above the Commission's low-risk benchmark utility return on common equity for all three divisions.

In January 2010, the Commission established a regulatory timetable for a written hearing process but also provided parties with the opportunity for the review to go to a Negotiated Settlement Process if desired. Commission Letter L-28-10 dated April 1, 2010, varied the regulatory timetable established in Order G-13-10 reflecting the preferences expressed by the major parties and to enable a Negotiated Settlement.

The Negotiated Settlement Process discussions for the Capital Structure and Equity Risk Premium took place on April 26 and 27, 2010 and an agreement was reached among the participants. The agreement was circulated to all Interveners, as well as the Commission on May 12, 2010, and was approved by the Commission on May 20, 2010.

Pacific Northern Gas Ltd.
2010 - 2011 Revenue Requirements
Order G-103-10

On March 4, 2010, the Commission approved the February 22, 2010 Interim Negotiated Settlement Agreement for PNG's 2010 Revenue Requirements application (Order G-33-10). On May 20, 2010, the Commission approved the agreement reached on the Capital Structure and Equity Risk Premium application under Order G-84-10.

PNG distributed updated regulatory schedules that reflected the terms in both the Interim Negotiated Settlement Agreement application and the CAP/ROE application Negotiated Settlement Agreement.

On June 3, 2010, participants of the negotiated settlement process agreed to accept PNG's regulatory schedules as filed and a final settlement was reached.

The final Negotiated Settlement Agreement for PNG's 2010 Revenue Requirements application, as issued on June 11, 2010 was approved and the interim delivery rates approved under Order G-130-09 set as permanent effective January 1, 2010.

Pacific Northern Gas (N.E.) Ltd.
2010-2011 Revenue Requirements
Order G-104-10

On March 4, 2010, the Commission approved the Interim Negotiated Settlement Agreement for PNG (N.E.)'s 2010 Revenue Requirements application (Order G-34-10). On May 20, 2010, the Commission approved the Negotiated Settlement Agreement in respect of the Capital Structure and Equity Risk Premium application under Order G-84-10.

PNG (N.E.) distributed the updated regulatory schedules that reflected the terms set forth in both the Interim Negotiated Settlement Agreement in respect of the application and the Capital Structure and Equity Risk Premium Negotiated Settlement Agreement.

On June 3, 2010, the NSP participants agreed to accept PNG (N.E.)'s regulatory schedules as filed and a final settlement was reached. The Final Agreement was circulated to all Interveners and the Commission on June 11, 2010.

The Final Negotiated Settlement Agreement for PNG (N.E.)'s 2010 Revenue Requirements application, as issued on June 11, 2010 was approved and the interim delivery rates approved under Order G-131-09 set as permanent effective January 1, 2010.

Pacific Northern Gas Ltd.
Sale of its 50 Percent Interest in the Pacific Trail Pipelines Limited Partnership
Order G-35-11

On February 15, 2011, PNG applied for approval under section 52 of the *Utilities Commission Act* to dispose of its 50 percent interest in Pacific Trail Pipelines Limited Partnership. PNG formed Pacific Trail Pipeline with Galveston LNG Inc. in 2006 in order to pursue the development of the proposed 463 kilometre, natural gas pipeline from Kitimat, BC to Summit Lake, BC (the KSL Pipeline). PNG and Galveston were equal partners.

In early 2010, Galveston sold 51 percent of its interest in the Kitimat LNG export terminal and 25.5 percent of its 50 percent interest in Pacific Trail Pipelines to Apache Canada Ltd. Later in 2010, EOG Resources Canada Inc. purchased Galveston, thereby obtaining a 24.5 percent interest in Pacific Trail Pipeline. In late 2010, Apache Canada and EOG Canada jointly approached PNG to purchase the remaining 50 percent interest in Pacific Trail Pipeline.

Following a written public hearing the Commission approved the sale by Pacific Northern Gas Ltd. of its 50 percent interest in Pacific Trail Pipelines Limited Partnership.

SHAW CABLESYSTEMS

Application to Continue to Use FortisBC Transmission Facilities - Suspension of Proceedings
Order G-114-10

Shaw Cablesystems Limited and Shaw Business Solutions Inc. (collectively, Shaw) has been using the electricity transmission infrastructure of FortisBC to support its telecommunication facilities for a number of years pursuant to several agreements, including the Transmission License Agreement dated July 1, 1999 between the two parties.

On October 1, 2009, FortisBC commenced Action in the Supreme Court of British Columbia seeking various remedies against Shaw including a declaration that the Transmission License Agreement was terminated. FortisBC Inc.'s application for an order suspending the proceeding before the Commission was granted, effective June 30, 2010. Fortis disputed the Commission's jurisdiction to hear Shaw's application.

Shaw filed a Statement of Defence and Counterclaim in the Action on October 29, 2009. Shaw also made an application to the Commission on October 26, 2009, seeking an order under section 70 of the *Utilities Commission Act* that FortisBC be required to allow Shaw continued access to its electricity transmission facilities.

Following a series of submissions and determinations by the Commission Panel that it did have the necessary jurisdiction and would hear Shaw's application, FortisBC applied for and received leave to appeal the Orders under which those determinations were made to the British Columbia Court of Appeal on June 2, 2010. On December 6, 2010, the BC Court of Appeal issued the Judgement of Mr. Justice Donald dismissing the FortisBC appeal.

In February 14, 2011, Shaw requested that the Commission continue to suspend the hearing of Shaw's application until March 31, 2011 to permit the finalization of a tentative agreement reached with FortisBC that would resolve the dispute. Shaw subsequently withdrew its application in a letter dated May 2, 2011, stating that it had finalized an agreement with FortisBC that resolves the dispute between the parties regarding the use of FortisBC's transmission facilities.

TERASEN UTILITIES

The Terasen Utilities changed their name on March 1, 2011 to FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc., FortisBC Energy (Whistler) Inc.

Terasen Gas Inc.
Reconsideration of Order G-28-10
Order G-68-10 and C-2-10

On March 9, 2010, Terasen Gas filed an application for Reconsideration of Order G 28 10 in which the Commission determined that the Tilbury Property Purchase was in the public interest and that a CPCN should be granted to Terasen Gas subject to conditions. The Reconsideration application stated that the original Contract of Purchase and Sale for the Property had been amended to extend the date for obtaining Commission approval until April 23, 2010.

The application was reviewed through a written process.

The Commission Panel determined that the Reconsideration application should be granted on the conditions proposed by Terasen Gas in the Reconsideration application, subject to the substitution of January 1, 2014 for January 1, 2013 in condition 3(e) proposed by Terasen Gas.

Under section 99 of the Act, Order G-28-10 was varied by rescinding paragraphs 2-7 and substituting them with new paragraphs as specified by the Panel. On April 14, 2010, Terasen Gas accepted the conditions as amended. The Commission granted a Certificate of Public Convenience and Necessity for the Tilbury Property Purchase subject to the conditions noted, under sections 45 and 46 of the *Utilities Commission Act*.

Terasen Gas (Whistler) Inc.
2010 - 2011 Revenue Requirements
Order G-138-10

On November 9, 2009 Terasen Whistler applied for approval of its 2010-2011 Revenue Requirements and Rates application to amend its rates, effective January 1, 2010, under sections 58, 60, 61 and 89 of the *Utilities Commission Act*. Interim rates were approved by the Commission under Orders G-136-09 dated November 19, 2009, as amended by Order G-136-09A dated December 15, 2009, effective January 1, 2010.

Terasen Whistler proposed unbundling the 2010-2011 tariff rate for General Service Rate into the following components:

i) A Basic Charge per Month of $7.50 effective January 1, 2010 for 2010 and 2011;

ii) A Delivery Charge per gigajoule of $11.610 commencing January 1, 2010 and $10.735 commencing January 1, 2011;

iii) A Gas Cost Recovery Charge per gigajoule of $6.691 (to be reset quarterly after Commission review of the Quarterly Gas Cost Reports) and a Rate Rider "A" of $1.817 per gigajoule, subject to quarterly review and resetting as appropriate, both effective January 1, 2010; and

iv) A Minimum Monthly Charge of $7.50.

The Commission approved the application, including the unbundled rate decrease of approximately 13.5 percent in 2010 and a further 2.9 percent in 2011, adjusted to reflect any Commission-approved quarterly adjustments to the Gas Cost Recovery Charge and ROE adjustments required under Commission Order G-158-09, subject to conditions.

The Pipeline component to change the sharing formula as it pertains to costs associated with the aerial crossings for the natural gas pipeline lateral was approved. The revised interim rates for Terasen Whistler will remain in effect until all Pipeline component costs are finalized or until addressed by further order of the Commission.

Reporting requirements:

- Terasen Whistler is to advise the Commission within 10 working days when the costs for the Pipeline component are finalized and the impact on rates are determined.
- Terasen Whistler is to provide, in all future project update reports to the Commission, updated internal cost estimates available as of the report date, including explanations for significant changes from previous estimates.

Terasen Gas Inc.
Biomethane Service Offering and Suporting Business Model - Salmon Arm and Catalyst Biomethane Projects
Order G-194-10

On June 8, 2010 Terasen Gas filed an application for approval of what it describes as an end-to-end business model encompassing the purchase of biogas and/or Biomethane for sale to its customers.

Terasen Gas is developing a number of initiatives which it believes are aligned with BC Government Policy and the *Clean Energy Act*. These are outlined in its 2010 Long Term Resource Plan. The Biomethane Service Offering application was the first of these initiatives to come before the Commission. The application is made up of three components:

- The Biomethane Supply Model which addresses the acquisition of a reliable supply of biogas.
- The Biomethane product offering which consists primarily of a rate offering allowing for the notional sale of Biomethane to Terasen customers on a voluntary basis.
- The cost allocation and recovery model addressing the recovery of costs for the product offering from the various customer groups.

Terasen's application sought approval of a number of proposals encompassing rates, cost recovery, supply and post implementation review which are related to the Program. Key among these are the following:

- approval of two projects, namely the Catalyst Project in Abbotsford, BC and the Columbia Shuswap Regional District Project in Salmon Arm, BC;
- the allocation of costs between all non by-pass customers and voluntary Biomethane gas purchasing customers; and
- a set of criteria allowing for the filing of future supply contracts.

The Panel was satisfied that the Program is in alignment with both British Columbia's energy objectives and Provincial Government policy and that there is sufficient demand and supply to justify moving forward. Accordingly, the Panel has determined the two Projects are in the public interest and has approved both of them as well as the related capital costs. However, the Panel noted that it would be prudent for Terasen to thoroughly test the proposed model in the marketplace before reaching a conclusion as to its full market potential.

With respect to Terasen's proposed role in the upgrading process, the Panel made no finding on the acceptability of this and directed that the upgrading business be sufficiently distinct so as to be severable if the Commission were to determine that this function should be conducted through a separate entity in the future. The Panel limited the total production of Biomethane for all projects to 250,000 GJ per year during the test period and set a maximum commodity price at $15.28 per GJ. The Panel approved the cost allocation methodology as proposed by Terasen as reasonable and in the public interest.

The Commission Panel allowed Terasen to move forward with a Biomethane Program on a test basis for a two year period. In introducing limitations on scope and a term for the test, the Panel believes that Terasen will learn valuable lessons which can be applied to the development of a model which will sustain the Program over the long term. It believes that taking this approach is prudent and in the best interests of Terasen ratepayers.

Terasen Gas Inc.
CNG LNG Reasons for Decision-Waste Management Section
Order G-6-11

On December 1, 2010, Terasen Gas applied under sections 59 to 61 of the *Utilities Commission Act*, for approval of a Compressed Natural Gas Fuelling Station Installation and Operating Agreement dated December 3, 2010 (WM Agreement) between Terasen and Waste Management of Canada Corporation (Waste Management). Under the WM Agreement, Terasen will install, operate and maintain a fuelling station for compressed natural gas on Waste Management's premises. Terasen submitted the WM Agreement to the Commission on a confidential basis, as part of a December 1, 2010 application that included approval of General Terms and Conditions for Compressed Natural Gas Service and for Liquefied Natural Gas Service, and for the capital expenditures related to the WM Agreement.

Terasen requested expedited approval of the WM Agreement as a Tariff Supplement by January 14, 2011, because Waste Management has ordered 20 CNG fuelled trucks and required service commencing on January 24, 2011. A written public hearing was established to review the application and a Regulatory Timetable that incorporated an expedited process for the WM Agreement.

The Commission Panel declined to approve the WM Agreement as filed. The Commission Panel concluded that any approval at this time must be on an interim basis, in order to adequately examine whether the business model proposed is in the public interest and whether the Fuelling Charges set out in the WM Agreement meet the requirements under sections 59 and 60 of the *Utilities Commission Act*.

The Panel approved an amended service agreement on an interim basis, providing the WM Agreement was changed by removing all references to Vehicle Reimbursement and Energy Efficiency and Conservation incentive grants and it is filed in standard Tariff Supplement format on a non-confidential basis.

Terasen Utilities
2010 Long Term Resource Plan
Order G-14-11

The Terasen Utilities filed an application on July 15, 2010 for acceptance of the 2010 Long Term Resource Plan under section 44.1(6) of the *Utilities Commission Act*. The plan provides a high level overview of future demand and supply source expectations over the next 20 year period and outlines in broad terms the actions required over the next four year period to ensure the energy needs of customers are met over the long-term. In addition, the application also covers the following:

- The changing British Columbia energy planning environment.
- Low and No-Carbon Initiatives.
- Energy Efficiency and Conservation-Demand Side Resources.
- Gas Supply and Regional Infrastructure Planning.

The application was reviewed through a written hearing process.

The Commission Panel accepted the Terasen 2010 Long Term Resource Plan under section 44.1(6) of the *Utilities Commission Act* as being in the public interest.

In its Decision, the Panel commented on the quality of the 2010 Long Term Resource Plan and made a number of directives concerning the preparation of future resource plans. These concern the following areas:

- The development of a longer term vision for Terasen Utilities.
- Integration of the Energy Efficiency and Conservation programs, New Initiatives and GHG reduction targets in demand forecasting.
- The approach to Demand forecasting given the new business environment.

An examination of Terasen's New Initiatives in terms of the regulatory questions raised, public interest concerns, competitive considerations and issues related to 'who pays' led to a Panel recommendation that the issues arising are sufficient to warrant a more formal process to address them at a future date.

Terasen Gas Inc.
Gas Supply Mitigation Incentive Program for November 1, 2010 to October 31, 2013 Three-Year Period
Order G-26-11

In response to Commission Order G-101-09, in which the Commission determined that the Gas Supply Mitigation Incentive Program should be reviewed in 2010, Terasen Gas submitted the subject GSMIP application on July 13, 2010. The proposed GSMIP contains an enhanced incentive formula to be applied to the Total Eligible Margin, includes all Southern Crossing Pipeline net mitigation revenue in the calculation, and has a term of three years.

After a written hearing process to review the application, the Commission denied the application on the grounds that while a properly structured GSMIP is likely to have benefits for customers as well as the shareholder of Terasen Gas, the Panel was not persuaded that the form of GSMIP proposed in the application will have sufficient benefits.

The Commission directed that the GSMIP that was in effect for the fiscal year 2010 be extended for one year commencing November 2010, and that Terasen Gas establish a working group including representatives from Terasen Gas, Commission staff, and other parties. The Working Group is to meet in early 2011 to revisit the objectives of GSMIP and to discuss the reformulation of the program to ensure alignment with the objectives. After the working group has completed its work, the Commission anticipates that Terasen Gas will file an application with the Commission by July 1, 2011 for a GSMIP commencing November 2011.

Terasen Gas Inc.
Fort Nelson Service Area for Approval to Amend Schedule of Rates
Order G-27-11

Terasen Gas Inc. Fort Nelson Service Area (TG Fort Nelson) is part of Terasen Gas Inc., the largest natural gas distribution utility in British Columbia. Rates have been set separately for TG Fort Nelson from the date of acquisition to the present.

On September 8, 2010, TG Fort Nelson submitted its 2011 Revenue Requirements application to the Commission seeking approval to recover a revenue deficiency through a permanent increase in its delivery rates, and to decrease the Revenue Stabilization Adjustment Mechanism rate rider, effective January 1, 2011.

After a written public hearing which concluded with the filing of Terasen's Reply Argument on January 12, 2011, the Commission approved TG Fort Nelson's proposal to recover a revenue deficiency through a permanent increase in its delivery rates, effective January 1, 2011. They also approved a decrease in the Revenue Stabilization Adjustment Mechanism rate rider, and revised rates as set out in the Evidentiary Update.

The Commission also approved:

- the continuation of existing deferral accounts and of the Revenue Requirements Application rate base deferral account for 2011 Revenue Requirements application costs as described in Section 7.6 of the application and previously approved by Commission Order G-173-10;
- the adoption of Accounting and Other Policy Changes consistent with the Terasen Gas 2010-2011 Negotiated Settlement Agreement as set out in Section 7 and 9 of the application;
- the proposed 2011 capital expenditures related to the Muskwa River Crossing Project as requested by TG Fort Nelson in the Evidentiary Update subject to conditions described in the Reasons for Decisions accompanying the Order; and
- the inclusion of Project costs, as presented in the Evidentiary update, in 2011 rate base.

Terasen Gas (Vancouver Island) Inc.
Victoria Regional Operations Centre
Order C-1-11

By application dated October 13, 2010 filed under sections 45 and 46 of the *Utilities Commission Act*, Terasen Gas (Vancouver Island) applied for a Certificate of Public Convenience and Necessity to purchase land in Langford, BC and to construct a new regional operations facility on the site. The Regional Facility will replace the current Victoria regional facility on Garbally Road and a small existing muster station in Langford.

The current lease for the Garbally Facility will expire on October 31, 2012, and Terasen Gas (Vancouver Island) wishes to move into the new facility in October 2012. The project is estimated to cost $14.3 million. Commission Order G-162-10 established a written public hearing, which was completed when Terasen Gas (Vancouver Island) filed its Reply Submission on December 23, 2010.

The British Columbia Old Age Pensioners Organization (BCOAPO) and the Commercial Energy Consumers Association of British Columbia (CEC) intervened in the proceeding. BCOAPO supported approval of the application, subject to three caveats that related to project cost, the long term usefulness, and potential disposal of the facility. CEC supported approval of the application and asked that the Commission Panel direct Terasen Gas (Vancouver Island) to address the efficiency of their operations in its next revenue requirements proceeding.

The Commission Panel was persuaded that the concept of a utility-owned Regional Facility has merit, and granted Terasen Gas (Vancouver Island) a CPCN with conditions to purchase the property in Langford. However the Panel found that they had not provided sufficient information and analysis to justify the sizing of the proposed Regional Facility. The Panel concluded that more analysis is required before making a decision on the Regional Facility, and Terasen Gas (Vancouver Island) was directed to file a comprehensive analysis that justifies the number of staff and service vehicles to be accommodated at the Regional Facility.

Appendices

APPENDICES

61 I Staff List

62 II Regulated Utilities

66 III Natural Gas Marketers Licensed in 2010/2011

67 IV Domestic Electricity Sales in 2010

68 V Domestic Gas Sales in 2010

69 VI Main Electric Transmission and Power Generating Facilities (Map)

70 VII Natural Gas and Gas Liquids Utilities (Map)

71 VIII Performance Indicators

Hearing/Alternative Dispute Resolution Days (Fiscal 2010/2011)

Customer Complaints and Inquiries (Fiscal 2010/2011)

Gas Marketer Complaints/Disputes

Staffing Levels

Directives Issued

Commission Expenditures and Cost of Regulation per Customer

Cost of Energy Regulation per Equivalent Gigajoule of Energy Sold

Cycle Times

80 IX Summary of Commission Orders issued in 2010/2011

101 X Standard Abbreviations & Acronyms

102 XI Glossary of Terms

106 XII Energy Conversion Factors

STAFF LIST

Following is a list of the April 2011 Commission staff, their positions and departments:

OFFICE OF THE CHAIR AND FINANCIAL ADMINISTRATION

Len Kelsey	Chair and Chief Executive Officer
Viki Vourlis	Manger of Finance, Human Resources, Administration & Assistant to the Chair/CEO
Denise Goddard	Financial Assistant
Kim Brooks	Financial & Contract Administrative Assistant

INFORMATION SERVICES GROUP

Erica M. Hamilton	Commission Secretary
Constance M. Smith	Assistant Commission Secretary
Alison H. Cormack	Information Services Officer
Kristen J. Olsen	Customer Service Specialist
Yvonne M. Lapierre	Administrative Clerk
Daniela Guest	Administrative Clerk
Mark Hudson	Web Administrator
Kathy Grasty	Receptionist

STRATEGIC SERVICES

Doug Chong	Director
Eileen Cheng	Senior Economist
Julie Tran	Senior Economist
Alison Richter	Senior Regulatory Analyst, First Nations and Sustainability

RATES AND FINANCE

Philip W. Nakoneshny	Director
Suzanne Sue	Senior Financial Analyst
Claudia McMahon	Senior Financial Analyst
Kristine Bienert	Senior Financial Analyst
Yolanda Domingo	Senior Financial Analyst

ENGINEERING AND ENERGY MARKETS

J. Brian Williston	Director
Cathy Marr	Senior Gas Engineer
Don Flintoff	Senior Electrical Engineer
Roy Bishop	Senior Electrical Engineer
J. Todd Smith	Gas Engineer

EMERGING TECHNOLOGIES AND INNOVATION

Mark Thomas	Director
Tatiana Obrejanu	Manager, Gas Marketing Programs

REGULATED UTILITIES

CROWN-OWNED ELECTRIC UTILITIES	SERVICE AREA
British Columbia Hydro and Power Authority 333 Dunsmuir Street Vancouver, BC V6B 5R3 Email Contact: regulatory.group@BChydro.com	Lower Mainland, Vancouver Island, Central and Northern BC and East Kootenay Regions
British Columbia Transmission Corporation[1] Suite 1100, Four Bentall Centre 1055 Dunsmuir Street PO Box 49260 Vancouver, BC V7X 1V5 Email Contact: bctc.regulatory@bctc.com	BC Transmission and Integrated Grid System

INVESTOR-OWNED ELECTRIC UTILITIES	SERVICE AREA
Corix Multi Utility Services Inc. (formerly Sun Rivers Services Corp.) #1128 Burdette Street Richmond, BC V6V 2Z3 Email Contact: glenn.laufer@corix.com	Lot 152, CLSR Plan 78619 Kamloops IR No. 1
Hemlock Valley Electrical Services Limited Berezan Management Group 20955 Hemlock Valley Road Agassiz, BC V0M 1A1 Telephone: (604) 797-4411 Email Contact: info@hemlockvalleyresort.com	Hemlock Valley
Silversmith Power & Light Corporation Box 369 New Denver, BC V0G 1S0 Email Contact: silversmith@netidea.com	Sandon, BC
FortisBC Inc. P.O. Box 130 Trail, BC V1R 4L4 Email Contact: electricity.regulatory.affairs@fortisbc.com	West Kootenay and Okanagan Regions of BC Princeton, Osprey Lake and Missezula Lake Areas
The Yukon Electrical Company Limited 100 - 1100 1st Avenue Whitehorse, Yukon Territory Y1A 3T4 Facsimile: (867) 668-3965	Lower Post

1 *British Columbia Transmission Corporation merged with BC Hydro effective July 5, 2010*

INVESTOR-OWNED NATURAL GAS OR PROPANE UTILITIES	SERVICE AREA
Big White Gas Utility P.O. Box 2039, Station "R" Kelowna, BC V1X 4K5 Email Contact: mvalcourt@bigwhite.com	Big White Ski Resort
Cal-Gas Inc. 4255 - 64th Avenue S.E. Calgary, Alberta T2C 2C8 Facsimile Contact: (403) 279-9098 Email Contact: jsereda@calgasinc.com	Canyon Ridge and Sonoma Pines
Corix Multi Utility Services Inc. 1128 Burdette Street Richmond, BC V6V 2Z3 Email Contact: glenn.laufer@corix.com	Lot 152, CLSR Plan 78619 Kamloops IR No. 1, Panorama and Sonoma Pines
Dockside Green Energy LLP. 301-2659 Douglas Street Victoria, BC, V8T4M3 Facsimile: (250) 360-1500	District Energy System, Victoria
Pacific Northern Gas Ltd. 950 - 1185 West Georgia Street Vancouver, BC V6E 4E6 Email Contact: info@png.ca	Summit Lake to Prince Rupert and Kitimat
Pacific Northern Gas (N.E.) Ltd. 950 - 1185 West Georgia Street Vancouver, BC V6E 4E6 Email Contact: info@png.ca	Dawson Creek, Rolla, Pouce Coupe, Tumbler Ridge, Fort St. John
Pacific Northern Gas Ltd. 950 - 1185 West Georgia Street Vancouver, BC V6E 4E6 Email Contact: info@png.ca	Granisle (Propane Grid System)
Port Alice Gas Inc. #101 - 4381 Dawson Street Burnaby, BC V5C 4B4 Email Contact: david@portalicegas.com	Port Alice (Propane Grid System)

INVESTOR-OWNED NATURAL GAS OR PROPANE UTILITIES	SERVICE AREA
continued...	
Stargas Utilities Ltd. P.O. Box 3002 Silver Star Mountain, BC V1B 3M1 Email Contact: stargas@shaw.ca	Silver Star resort community
Sun Peaks Utilities Co., Ltd. 1280 Alpine Road Sun Peaks, BC V0E 1Z1 Email Contact: utilities@sunpeaksresort.com	Resort area north of Kamloops
FortisBC Energy Inc.[2] 16705 Fraser Highway Surrey, BC V4N 0E8 Email Contact: gas.regulatory.affairs@fortisbc.com	Lower Mainland, Fort Nelson, Central and Northern Interior, the Kootenays and the Okanagan
FortisBC Energy (Vancouver Island) Inc.[3] 16705 Fraser Highway Surrey, BC V4N 0E8 Email Contact: gas.regulatory.affairs@fortisbc.com	Sunshine Coast, Powell River, and Vancouver Island north to Campbell River, west to Port Alberni, and south to Victoria
FortisBC Energy (Whistler) Inc.[4] 16705 Fraser Highway Surrey, BC V4N 0E8 Email Contact: gas.regulatory.affairs@fortisbc.com	Whistler (Propane Grid System)

INVESTOR-OWNED STEAM HEAT UTILITY	SERVICE AREA
Central Heat Distribution Limited 720 Beatty Street Vancouver, BC V6B 2M1 Email Contact: CHDL@telus.net	Downtown Vancouver

2 *Formerly Terasen Gas Inc., legal name change effective March 1, 2011*

3 *Formerly Terasen Gas (Vancouver Island) Inc., legal name change effective March 1, 2011*

4 *Formerly Terasen Gas (Whistler) Inc., legal name change effective March 1, 2011*

REGULATED COMPANY COMPULSORY AUTOMOBILE INSURANCE	SERVICE AREA
Insurance Corporation of British Columbia Suite 517 - 151 West Esplanade North Vancouver, BC V7M 3H Email Contact: regaffairs@ICBC.com	Province of BC

MUNICIPALLY-OWNED ELECTRIC UTILITIES	SERVICE AREA

Municipally-owned electric utilities are not regulated under the Utilities Commission Act. Only the City of Nelson's electric utility with service outside of the Municipal boundaries is subject to regulation by the British Columbia Utilities Commission.

City of Grand Forks Box 220 Grand Forks, BC V0H 1H0	Grand Forks
City of Kelowna 1435 Water Street Kelowna, BC V1Y 1J4	Kelowna
City of Nelson (also known as Nelson Hydro) 502 Vernon Street Nelson, BC V1L 4E8	Nelson (urban and rural areas)
City of New Westminster 511 Royal Avenue New Westminster, BC V3L 1H9	New Westminster
City of Penticton 616 Okanagan Avenue East Penticton, BC V2A 3K6	Penticton
District of Summerland Box 159 Summerland, BC V0H 1Z0	Summerland

NATURAL GAS MARKETERS LICENSED IN 2010/2011

Licence No.	Gas Marketer
A-5-10	Direct Energy (B.C.) Limited
A-7-10	Bluestream Energy Inc.
A-16-10	AltaGas Energy Limited Partnership
A-19-10	Connect Energy Partnership
A-20-10	Just Energy (B.C.) Limited Partnership Doing Business as: Commerce Energy (commercial customers) Just Energy (B.C.) Limited Partnership (residential customers)
A-21-10	Smart Energy (BC) Ltd.
A-22-10	Cascadia Energy Ltd.
A-23-10	Bluestream Energy Inc.
A-24-10	Universal Energy Corporation
A-25-10	Ag Energy Co-operative Ltd. Operating as: Firefly Energy
A-27-10	MXEnergy (Canada) Ltd.
A-28-10	Active Energy Corp. Operating as: Active Renewable Marketing Limited
A-29-10	Summitt Energy BC LP
A-30-10	Access Gas Services Inc.
A-31-10	Superior Energy Management Gas LP
A-32-10	Planet Energy (B.C.) Corp.
A-35-10	AltaGas Energy Limited Partnership
A-37-10	Direct Energy (B.C.) Limited
A-38-10	AltaGas Ltd.
A-1-11	Superior Energy Management Gas LP
A-2-11	Access Gas Services Inc.
A-3-11	MXEnergy (Canada) Ltd.
A-4-11	Active Energy Corp. Operating as: Active Renewable Marketing Limited
A-5-11	MXEnergy (Canada) Ltd.
A-6-11	Access Gas Services Inc.
A-7-11/ A-38-10A	AltaGas Ltd.

DOMESTIC ELECTRICITY SALES IN 2010

	Customers (#)	Revenue ($000)	Sales (GW.h)
CROWN-OWNED ELECTRIC UTILITY			
BC Hydro and Power Authority	1,848,093	3,157,209	48,923
MUNICIPALLY-OWNED ELECTRIC UTILITIES			
City of Grand Forks	2,123	3,024	36.26
City of Kelowna	14,547	27,650	316.6
City of Nelson (urban)	5,685	8,090	95
City of Nelson (rural)	4,061	4,633	62
City of New Westminster	31,219	31,310	427
City of Penticton	16,858	27,622	321.86
District of Summerland	5,546	8,772	91
Total Municipally-Owned	80,039	111,101	1,349.72
INVESTOR-OWNED ELECTRIC UTILITIES			
FortisBC Inc.	112,250	195,026	2,165
Hemlock Electrical Services Limited	238	233	1.3
Silversmith Light & Power Corporation	11	34	0.08
Corix Multi-Utility Services Inc.			
CMUS – Sun Rivers & Sonoma Pines	926	985	12.04
The Yukon Electrical Company Limited			
Lower Post BC	90	265	1.88
Total Investor-Owned	113,515	196,543	2,180
TOTAL ALL ELECTRICAL UTILITIES	2,041,647	3,464,853	52,453

ELECTRICITY NOTES

1. 1 gigawatt hour (GW.h) = 1 million kilowatt hours.
2. Figures reported are for the 2010 calendar year. Customers reported are as at December 31, 2010.
3. Revenue and sales for BC Hydro and FortisBC Inc. are net of sales to other reporting electrical utilities identified in this table.

DOMESTIC GAS SALES IN 2010

	Customers (#)	Revenue ($000)	Sales (GW.h)
INVESTOR-OWNED NATURAL GAS UTILITIES			
FortisBC Energy Inc. (formerly Terasen Gas Inc.)			
Lower Mainland Division	588,441	984,967	110,343
Inland Division	231,156	295,785	43,379
Columbia Division	22,675	33,320	7,070
Fort Nelson Division	2,388	4,649	577
Revelstoke	1,571	3,554	195
FortisBC Energy (Vancouver Island) Inc. (formerly Terasen Gas (Vancouver Island) Inc.)			
Vancouver Island, Powell River and Sunshine Coast areas	100,140	193,410	31,018
FortisBC Energy (Whistler) Inc. (formerly Terasen Gas (Whistler) Inc.	2,592	13,587	753
Pacific Northern Gas (N.E.) Ltd.			
Fort St. John Inc./Dawson Creek Division	17,493	26,886	4,345
Tumbler Ridge Division	1,185	1,622	945
Pacific Northern Gas Ltd. (includes Granisle Grid)	20,727	65,334	4,197
Corix Multi-Utility Services Inc.			
Sun Rivers, Sonoma Pines	740	360	23
CMUS - Panorama	212	822	32
CalGas Inc. - Kickinghorse	122	298	19
CalGas Inc. – Canyon Ridge	21	14	1
Big White Gas Utility Ltd.	235	920	40
Port Alice Gas Inc.	248	384	13
Sun Peaks Utilities Co. Ltd.	868	1,519	72
Stargas Utilities Ltd.	256	432	37
TOTAL ALL GAS UTILITIES	991,070	1,627,863	203,059

GAS NOTES

1. 1 gigajoule (GJ) is approximately equivalent to 0.910 mcf (mcf = one thousand cubic feet) or 0.0258 103m3 of natural gas or 0.376 mcf of propane vapour in L.P. gas grid systems.
2. Figures reported are for the 2010 calendar year. Customers reported are as at December 31, 2010.
3. Sales of TJ shown include sales to end-use customers plus gas owned by customers and transported to their industrial operations by utilities.
4. Revenues reported for natural gas utilities include only transportation margins for large industrial customers who have purchased gas supplies directly from producers or aggregators.

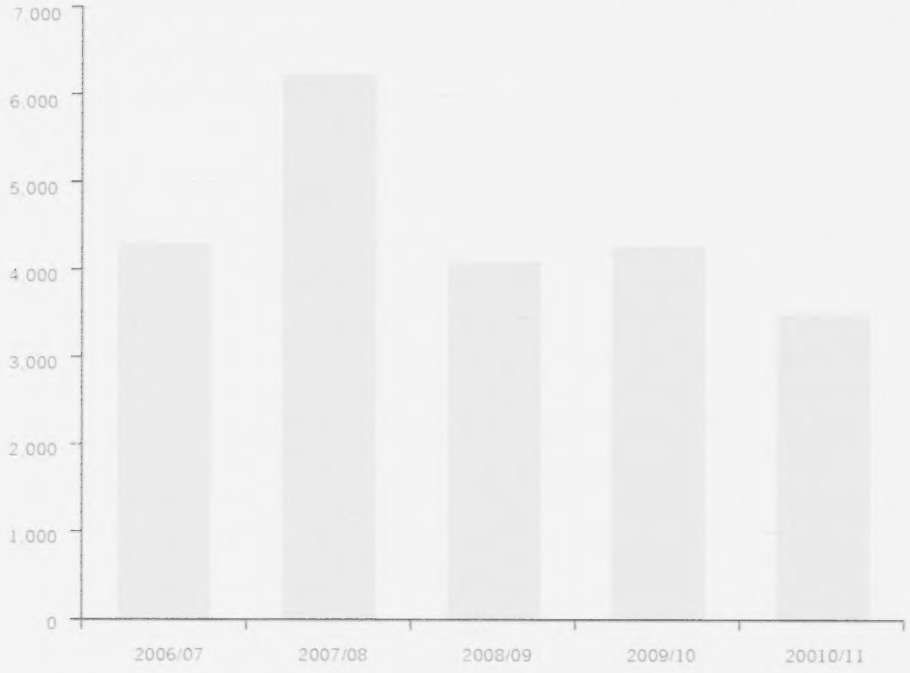
MAIN ELECTRIC TRANSMISSION AND POWER GENERATING FACILITIES

NATURAL GAS AND GAS LIQUIDS UTILITIES

PERFORMANCE INDICATORS

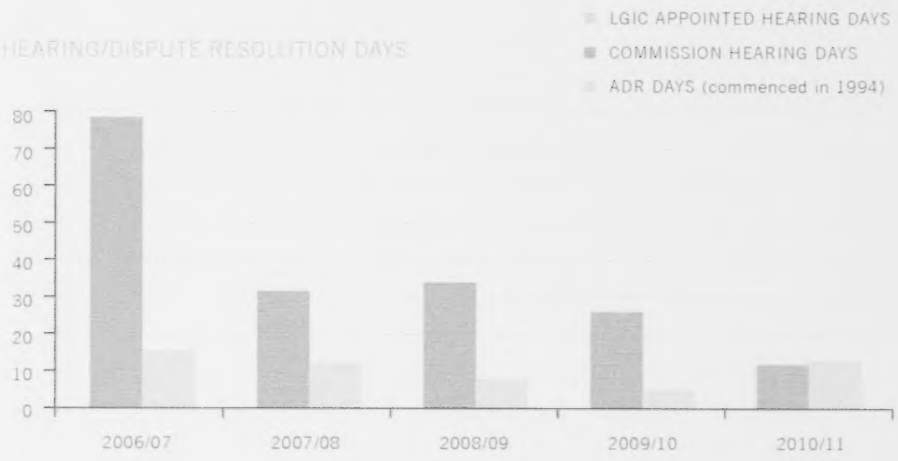
Correspondence received by the Commission consists of customer complaints, utility applications, hearing documents, requests for information/assistance (not related to a proceeding), and utility reports. The graphs below do not include customer complaints received by telephone, fax or email or telephone requests received by the Information Services Group for Commission documents. These requests are processed immediately upon receipt and are not entered into the document tracking system. After a spike in the amount of correspondence received and processed by Commission staff in 2007/08, the volume returned to a level generally consistent with the previous three years.

TOTAL CORRESPONDENCE RECEIVED



HEARING AND ALTERNATIVE DISPUTE RESOLUTION DAYS

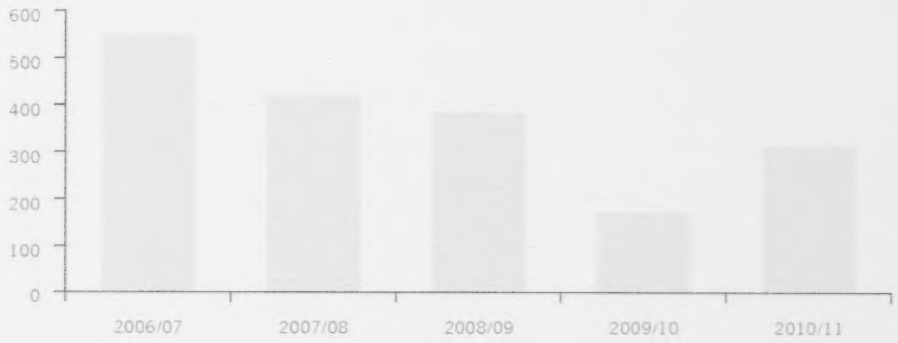
Since 2003/04, Alternative Dispute Resolution, the use of formulas for setting ROEs, and multi-year performance based settlements all contributed to the declining trend in the number of hearing days.



CUSTOMER COMPLAINTS AND INQUIRIES

Inquiries from Utility Customers concerning Terms and Conditions of Utility Service, Quality of Service, Rate Increases, Billing and Payment Requirements, Disconnections, etc.

Most complaints and inquiries are resolved through discussions between the customer and the utility concerned. Unresolved issues are often referred to the Commission. The number of complaints and inquiries this year increased to 309 up from 173 reported last year and down from the 380 and 412 in the previous two years.



SUMMARY OF 2010/2011 CUSTOMER COMPLAINTS

	Category Breakdown	Total
Big White Propane Utility		
BC Hydro and Power Authority		181
General Complaints	119	
Billing	44	
Power Surges/Outages	6	
Disconnected/Security Deposit Required	12	
British Columbia Transmission Corporation		
Cal-Gas Inc.		
Central Heat Distribution Limited		
Central Coast Power Corporation		
Corix Multi Utility Services Ltd.		
FortisBC Inc.		33
Hemlock Valley Electrical Services Ltd.		
Insurance Corporation of British Columbia		11
Nelson Hydro		1
Pacific Northern Gas Ltd.		6
Pacific Northern Gas (N.E.) Ltd.		
Port Alice Gas Inc.		
Silversmith Power and Light		
Stargas Utilities Ltd.		
Sun Peaks Utilities Co. Ltd.		
FortisBC Energy Inc. (formerly Terasen Gas Inc.)		70
General Complaints	32	
Billing	24	
Disconnected/Security Deposit Requirement	14	
FortisBC Energy (Vancouver Island) Inc. [formerly Terasen Gas (Vancouver Island] Inc.		7
Total 2010/2011 Complaints/Inquiries		309

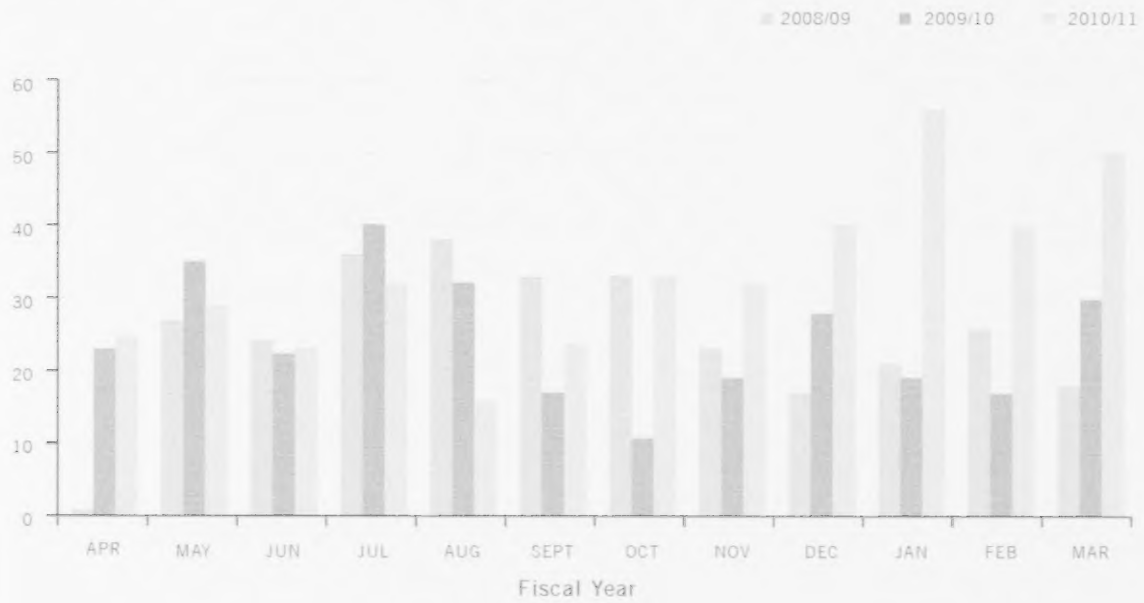
CUSTOMER COMPLAINTS REGARDING THE CUSTOMER CHOICE PROGRAM AND GAS MARKETERS

The Commission accepts complaints from the public who have a general complaint or concern about a gas marketer and who may or may not have entered into an agreement with a gas marketer for the Customer Choice Program. The types of complaints may include customer service, program administration, or gas marketer Code of Conduct issues such as salesperson conduct or marketing practices.

Many complaints are successfully resolved between the complainant and the gas marketer without the involvement of the Commission. Complainants should attempt resolution of the complaint with the gas marketer prior to contacting the Commission. However, in instances where resolution is not achieved, the Commission accepts complaints in writing, either by email, fax, or letter.

In the fiscal year 2010, the Commission processed a total of 286 written complaints. This figure represents the number of originating written complaints received from the complainants and does not include secondary responses from the complainants, gas marketer responses, follow-up telephone enquiries, or Commission correspondence related to each complaint. There are instances when customers request to revisit a written complaint filed previously if they are not satisfied with the resolution received; customer requests to review complaints that were previously filed with the Commission are not included in the figure.

GAS MARKETER CUSTOMER COMPLAINTS



CUSTOMER DISPUTES OF GAS MARKETER CONTRACTS

A dispute process is available for customers who have signed a contract with a gas marketer and wish to dispute their contract. Contracts may be disputed for a number of reasons including contract term, contract price, validity of the contract, and issues on gas marketers' non-compliance with the Code of Conduct.

Some disputes are successfully resolved directly between the customer and the gas marketer. Customers are advised to attempt resolution of their dispute directly with the gas marketer prior to seeking third party resolution from the Commission by lodging a dispute through the dispute resolution process.

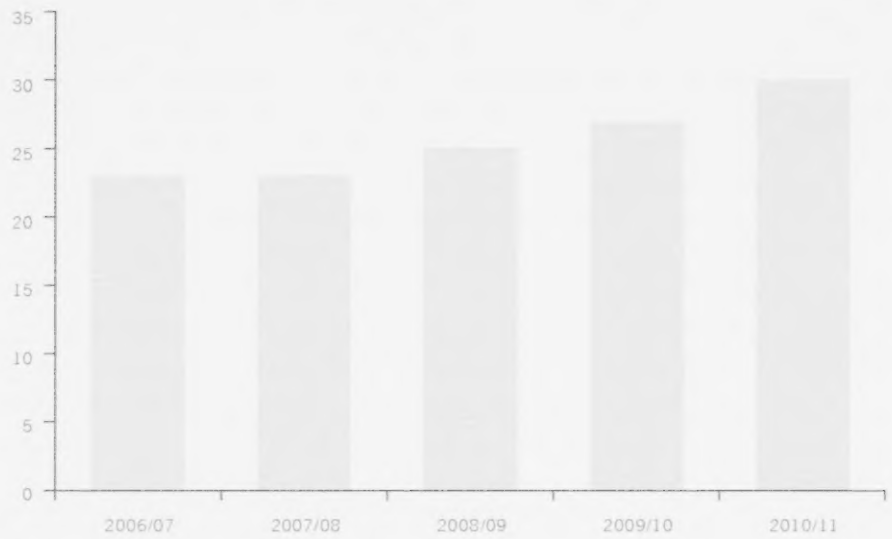
In 2010/2011, the Commission received 2,554 disputes through the dispute resolution system. This figure includes disputes adjudicated by the Commission and may include non-contested disputes in which the gas marketer agreed to cancel a customer's contract of their own accord, without a Commission determination. In adjudicated disputes, the Commission determination could either uphold the validity of a customer contract or order the cancellation or termination of a contract where non-compliance with the Code of Conduct is identified.

GAS MARKETER CUSTOMER DISPUTES

APPENDIX VIII

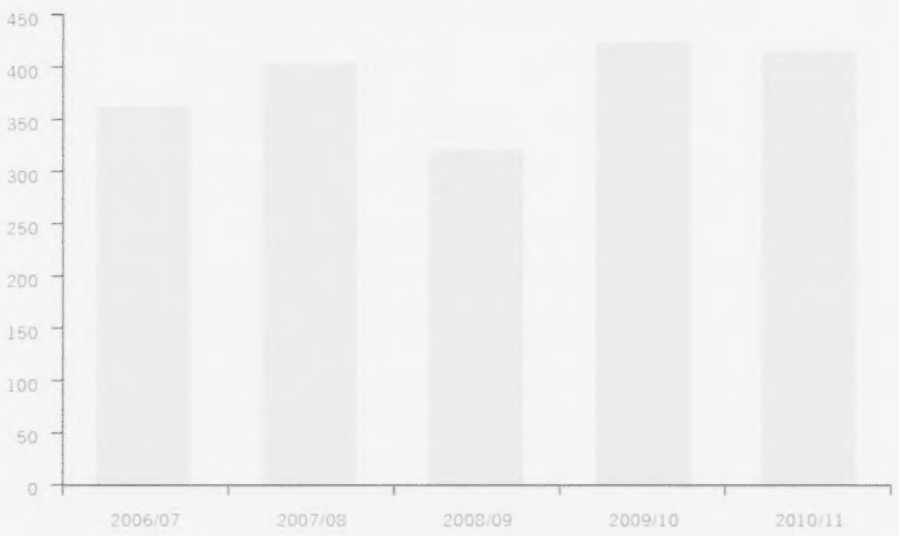
STAFFING LEVELS

Staffing levels increased from 2009/1010.



DIRECTIVES ISSUED

The number of Orders and Letters of Direction issued in 2010/11 was 415; a decrease from 424 in 2009/2010.

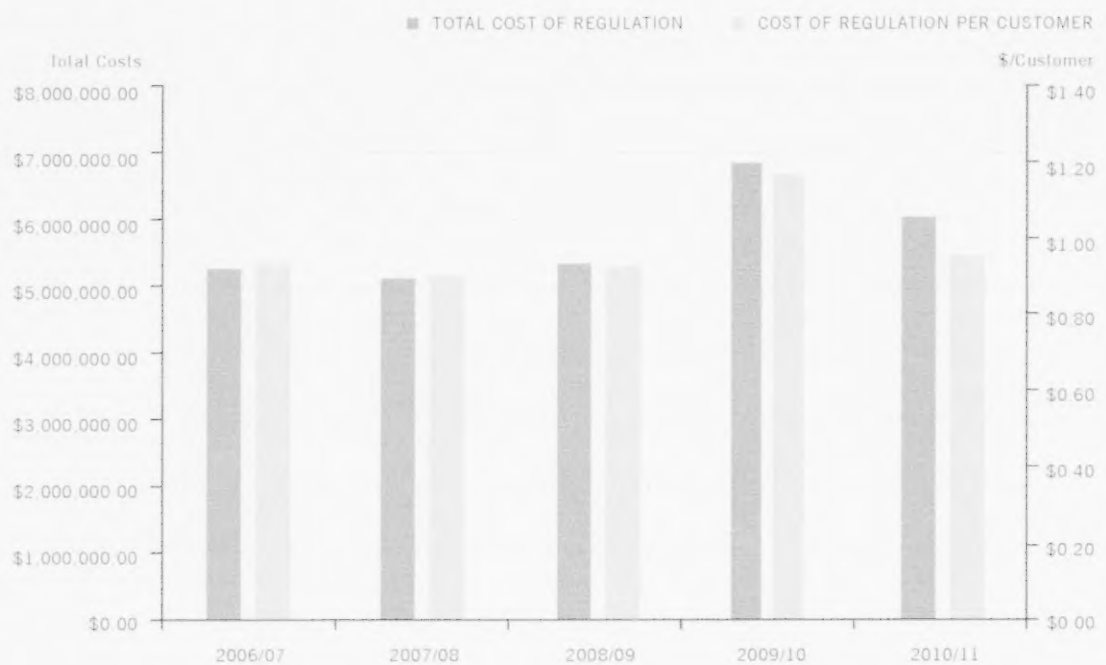


COMMISSION EXPENDITURES AND COST OF REGULATION PER CUSTOMER

The Commission's total expenditure for the reporting year was $6,031,155.17; a decrease of 9 percent from 2009/10. This was caused primarily by a decrease in the intensity of regulatory activity and the termination of the Section 5 Inquiry.

The cost of regulation per customer is calculated by dividing Commission expenditures by the total number of customers of regulated utilities.

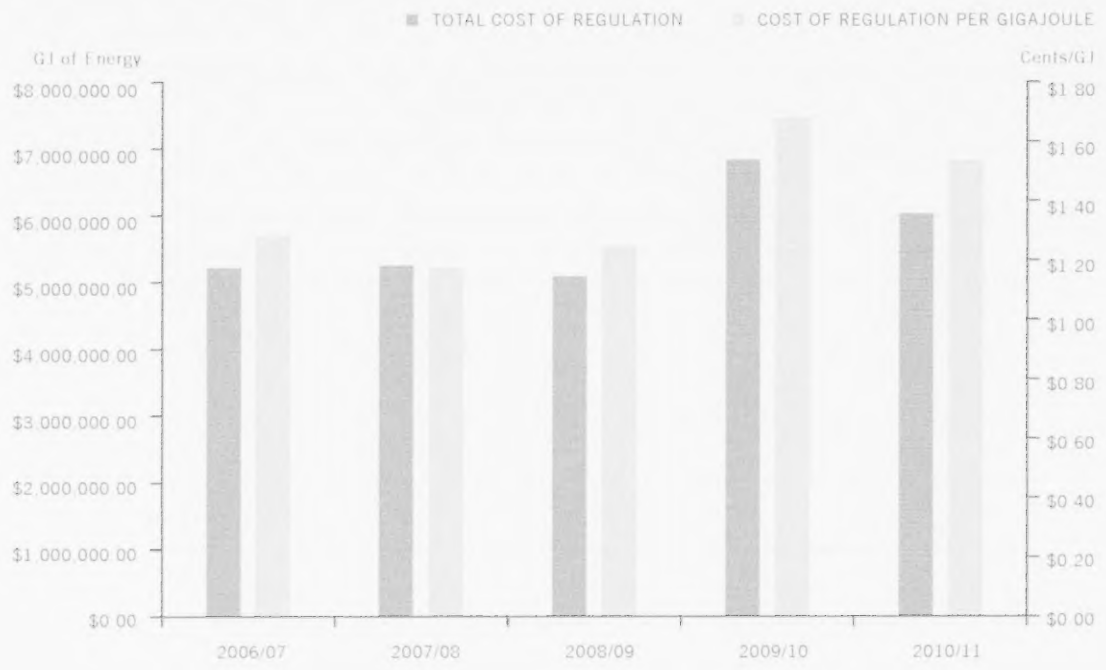
COMMISSION COSTS



COST OF ENERGY REGULATION PER EQUIVALENT GIGAJOULE OF ENERGY SOLD (CENTS)

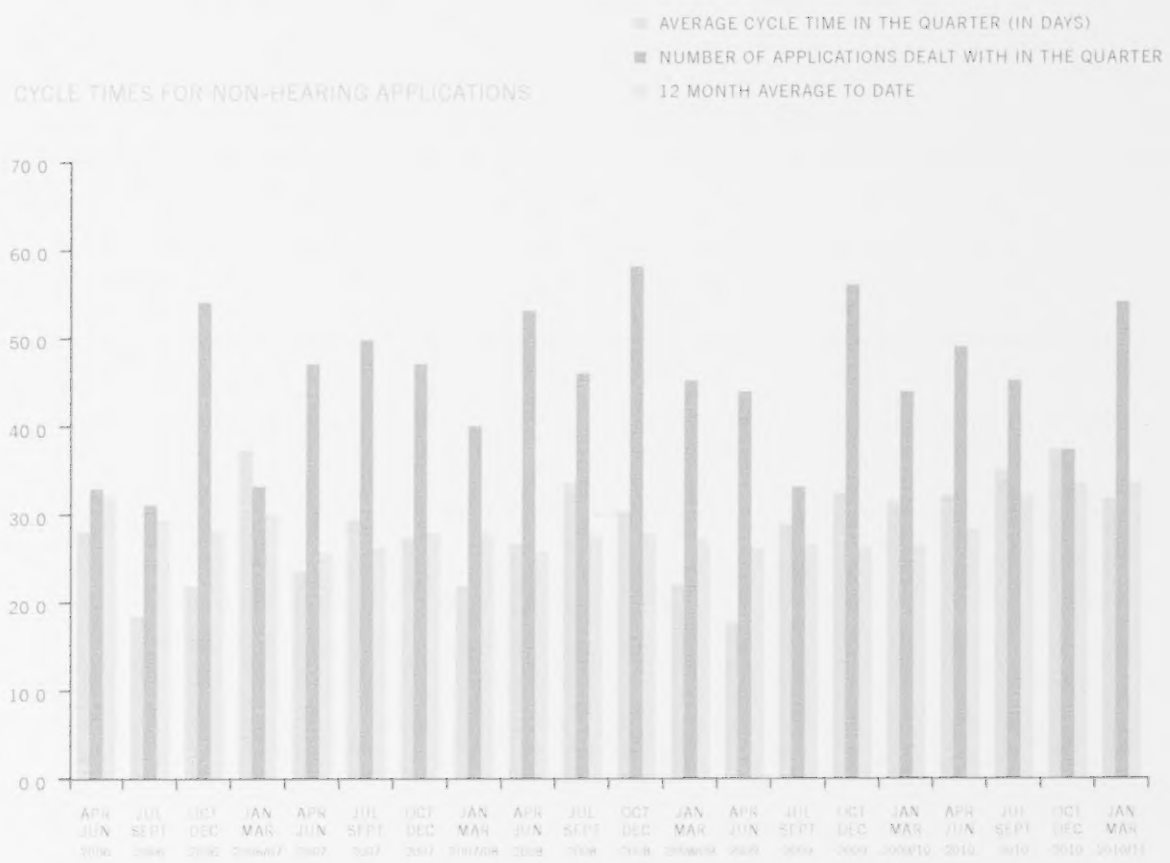
The cost of regulation per gigajoule (equivalent) of energy sold is calculated by dividing Commission energy regulation expenditures by the amount of energy sold or transported by utilities in that year.

COST OF ENERGY REGULATION



CYCLE TIMES

The following graph portrays the cycle or turnaround times - the time elapsed between the receipt of an application and a Commission decision - related to Non-Hearing applications which are usually straightforward and not controversial. These applications are managed by staff review and analysis, often with supplementary information requests and responses from the utility, but without a formal public review. Average cycle times, by quarter was 32 calendar days in 2010/2011.



More complex applications require a public review process, usually through an oral public hearing, a written public hearing, or a negotiated settlement process. Oral public hearings the most complex and typically take seven to eight months between receipt of the application and the issuance of the Commission Decision. The written hearing process cycle times average about six months, and applications that proceed by way of the negotiated settlement process take about four months on average between receipt and disposition.

SUMMARY OF COMMISSION ORDERS ISSUED IN 2010/2011

Copies of the Commission's Orders are available from the BCUC web site at: *http://www.bcuc.com/OrderIndex.aspx*

GENERAL ORDERS

Order No.	Utility	Description
G-61-10	CORIX	Approval of an Increase to the Gas Cost Recovery Charge –Panorama Mountain Resort
G-62-10	CORIX	Approval of Propane Annual Contracting Plan for Panorama Mountain Resort
G-63-10	FORTISBC	Reconsideration of Order G-24-10 – Shaw Cablesystems application to Continue to use FortisBC's Transmission Facilities – Notice of Oral Hearing/Reconsideration Denied – Reasons for Decision
G-64-10	BCTC	F2011 Information Filing/Deferral Account to Record 2011 Capital Portfolio Project Sustaining Costs – Amendment to Directive No. 1 of Order G-43-10
G-65-10	ICBC	Streamlined Regulatory Process application – Reasons for Decision
G-66-10A	TGVI	Extend the Maturity date of the Existing Term Credit Agreement between Terasen Gas (Vancouver Island), Royal Bank of Canada and Other Lenders
G-67-10	BC HYDRO	Include in the SMI Regulatory Account the Actual F2010 Smart Metering Program and Smart Grid Program Operating Costs
G-68-10	TERASEN GAS	Tilbury Land Purchase Reconsideration – Reasons for Decision
G-69-10	FORTISBC	2009 Rate Design and Cost of Service – Amended Timetable – Reply Evidence
G-70-10	TERASEN GAS	Firm Transportation Service Agreement with Westcoast Energy Inc. and Accounting Treatment of Stage 1 Costs for a Pipeline Expansion Study
G-71-10	BCTC	Columbia Valley Transmission Certificate of Public Convenience and Necessity Project – Amended Regulatory Timetable – Submission of Evidence
G-72-10	DOCKSIDE GREEN ENERGY	Application for Approval of a Supplemental Tariff for Delta Ocean Pointe Resort and Spa
G-73-10	BC HYDRO	Transmission Service Rate Customer Baseline Load F2009 and F2010 Dispute-Determination and Notice of Written Hearing
G-74-10	FORTISBC	Application for Approval of a Fifth Amending Agreement to the Credit Agreement
G-75-10	ICBC	A Filing on the Report on Finding from the Independent Third Party Review of ICBC's Regional Claim Centres Financial Allocation and Specified Financial Allocation Functions – Reasons for Decision
G-76-10	TERASEN GAS	Application Regarding Rate Schedule 14A for the 2010/11 Gas Contract Year

Order No.	Utility	Description
G-77-10	BC HYDRO	Transmission Service Rate Mount Polley Mining Corporation - F2009/F2010 Customer Baseline Load
G-78-10	BC HYDRO	Application for Permission to Retire Assets-Lake Buntzen 2 Generating Station
G-79-10	TERASEN GAS	Application for Approval to Issue Medium Term Note Debentures
G-80-10	BC HYDRO	Application to Cancel Tariff Supplement No. 47 and Disposition of Related Funds in Connection with service to Meziadin Lake
G-81-10	BC HYDRO	Stave Falls Spillway Gates Replacement Project
G-82-10	BCUC	Recovery of Commission Costs for the 2010/11 Fiscal Year
G-83-10	BCTC	Application for Fiscal 2010 Transmission Revenue Requirement and Rate Changes – Amended Timetable
G-84-10	PNG-PNG(N.E.)	Application for Capital Structure and Equity Risk Premium – Negotiated Settlement
G-85-10	ICBC	2010 Revenue Requirements – Regulatory Timetable
G-86-10	FORTISBC	2009 Rate Design – Supplementary Regulatory Timetable
G-87-10	BCTC	F2011 Capital Plan Update – Reasons for Decision
G-88-10	BC HYDRO	Application for Approval to Establish a Regulatory Asset Regarding Liability Provision for Environmental Compliance and Remediation
G-89-10	BCTC	Reliability Management System Termination Agreement with the Western Electricity Coordinating Council
G-90-10	BC HYDRO	Reliability Management System Termination Agreement with the Western Electricity Coordinating Council
G-91-10	FORTISBC	Reliability Management System Termination Agreement with the Western Electricity Coordinating Council
G-92-10	FORTISBC	Mandatory Reliability Standards registration as Resource Planner and Transmission Service Provider
G-93-10	SHAW CABLESYSTEMS	Continued Use of FortisBC Transmission Facilities – Procedural Conference Reasons for Decision/Revised Regulatory Timetable
G-94-10	BCTC	Certificate of Public Convenience and Necessity for the Columbia Valley Transmission Project – Revised Timetable

Order No.	Utility	Description
G-95-10	AQUILON POWER	Mandatory Reliability Standards Registration for the function of Purchasing Selling Entity
	INTERCONTINENTAL PULP MILL	Mandatory Reliability Standards Registration for the function of Distribution Provider
	NORTHWOOD PULP MILL	Mandatory Reliability Standards Registration for the function of Distribution Provider
	PRINCE GEORGE PULP AND PAPER	Mandatory Reliability Standards Registration for the function of Distribution Provider
	TEMBEC CRS	Mandatory Reliability Standards Registration for the function of Distribution Provider
	TEMBEC LAP	Mandatory Reliability Standards Registration for the functions of Distribution Provider and Load Serving Entity
	TOLKO INDUSTRIES	Mandatory Reliability Standards Registration for the functions of Distribution Provider, Generator Operator, Generator Owner, and Load Serving Entity
G-96-10	BEAR MOUNTAIN WIND LIMITED PARTNERSHIP	Mandatory Reliability Standards Registration for Transmission Operator, Transmission Owner, Generator Operator and Generator Owner
	ZEBALLOS LAKE HYDRO LIMITED PARTNERSHIP	Mandatory Reliability Standards Registration for Transmission Operator and Transmission Owner
G-97-10	DOMTAR KAMPLOOPS	Mandatory Reliability Standards Registration for Distribution Provider and Load-Serving Entity
	SHELL ENERGY NORTH AMERICA (CANADA)	Mandatory Reliability Standards Registration for Purchasing - Selling Entity
G-98-10	BCUC	Inquiry into British Columbia's Long-Term Transmission Infrastructure - Termination of Long-Term Electricity Transmission Inquiry
G-99-10	BC HYDRO	F2011 Revenue Requirements - Amended Regulatory Timetable
G-100-10	TERASEN GAS	Fort Nelson Service Area - Second Quarter Gas Costs Report and Rate Changes effective July 1, 2010
G-101-10	TERASEN GAS	Revelstoke Service Area - Second Quarter Gas Costs Report and Propane Commodity Changes Effective July 1, 2010
G-102-10	TERASEN WHISTLER	Gas Cost Recovery Charge Effective July 1, 2010
G-103-10	PNG	F2010 -Revenue Requirements - Final Negotiated Settlement Agreement

Order No.	Utility	Description
G-104-10	PNG(N.E.)	F2010 -Revenue Requirements - Final Negotiated Settlement Agreement
G-105-10	SHAW CABLESYSTEMS	Continue Use of FortisBC Transmission Facilities - Request for Extension to File Information Request Responses/Reasons for Decision
G-106-10	TERASEN GAS	2010 Second Quarter Gas Costs Report and Rate Changes Effective July 1, 2010 for the Lower Mainland, Inland, Columbia Service Areas
G-107-10	PNG(N.E.)	Increase to Allowable Indebtedness under Pacific Northern Gas's Revolving Credit Facility
G-108-10	BCTC	F2011 Transmission Revenue Requirements and Rate Changes – Amended Regulatory Timetable
G-109-10	TERASEN GAS	Biomethane Service Offering and Supporting Business Model - Salmon Arm Biomethane Project and Catalyst Biomethane Project - Notice of Written Hearing
G-110-10	BC HYDRO	Large General Service Rate Application – Reasons for Decision
G-111-10	BC HYDRO	2010 Standards of Conduct
G-112-10	FORTISBC	2011 Capital Expenditures Plan - Notice of Written Hearing and Regulatory Timetable
G-113-10	PNG	Issuance of a Guarantee and Granting of Security for the Guarantee - McNair Creek Hydro Limited Partnership for PNG's Shares in MC Hydro Holding Corp.
G-114-10	SHAW CABLESYSTEMS	Application to Continue to Use FortisBC Transmission Facilities - Suspension of Proceedings
G-115-10	ICBC	Changes to Universal Compulsory Automobile Insurance for Fleetplan Vehicles - Reasons for Decision
G-116-10	TERASEN GAS	Mandatory Reliability Standards Registration for Load Serving Entity
G-117-10	CARIBOO PULP & PAPER COMPANY	Mandatory Reliability Standards Registration for Distribution Provider
G-118-10	TECK METALS INC.	Mandatory Reliability Standards Registration for Transmission Owner, Transmission Operator, Generator Owner, and Generator Operator
G-119-10	ICBC	Year 3 Basic Insurance Rate Adjustments per G-4-08 (Tariffs)
G-120-10	TERASEN GAS	Gas Supply Mitigation Incentive Program for the November 1, 2010 to October 31, 2013 Three-Year Period - Negotiated Settlement Process and Timetable
G-121-10	RIO TINTO ALCAN	Mandatory Reliability Standards Registration for Generator Operator, Generator Owner, Transmission Owner, Transmission Operator, Distribution Provider and Load Serving Entity

Order No.	Utility	Description
G-122-10	CLOUDWORKS ENERGY INC.	Mandatory Reliability Standards Registration for Generator Operator, Generator Owner, Transmission Owner, and Transmission Operator
G-123-10	TRANSCANADA ENERGY LTD.	Mandatory Reliability Standards Registration for Purchasing - Selling Entity
G-124-10	TERASEN UTILITIES	2010 Long Term Resource Plan - Procedural Conference
G-125-10	BC HYDRO	Hugh Keeleyside Spillway Project - Notice of Written Hearing and Regulatory Timetable
G-126-10	SINIXT NATION	Reconsideration of BC Hydro Waneta Transaction Order G-12-10 - Reasons for Decision
G-127-10	FORTISBC	Application for Approval for Interim Rate Relief to flow-through the BC Hydro Power Purchase interim rate increase
G-128-10	BC HYDRO	Mandatory Reliability Standard - Change in Registration
G-129-10	BC HYDRO	Approval of Mitigation Plan Filings
G-130-10	FORTISBC	Approval of Mitigation Plan Filings
G-131-10	RIO TINTO ALCAN	Approval of Mitigation Plan Filings
G-132-10A	TOLKO INDUSTRIES	Approval of Mitigation Plan Filings
G-133-10	TERASEN GAS	Certificate of Public Convenience and Necessity for Kootenay River Crossing - Regulatory Timetable
G-134-10	BC HYDRO	Approval to Discontinue the "Pre-Authorized Payment with Discount" provision in BC Hydro's Electric Tariff
G-135-10	BC HYDRO/BCTC	Fiscal 2010 Transmission Revenue Requirement and Rate Changes – Final Commission Determination
G-136-10	BC HYDRO	F2011 Revenue Requirements - Second Procedural Conference
G-137-10	ICBC	F2010 Revenue Requirements - Determination
G-138-10	TERASEN WHISTLER	2010-2011 Revenue Requirements - Determination
G-139-10	BC HYDRO	Transmission Service Rate – Customer Baseline Load F2009 and F2010 Dispute with Buckeye Canada
G-140-10	CATALYST PAPER	Mandatory Reliability Standards Registration for Crofton, Elk Falls, Port Alberni and Powell River Divisions as Transmission Owner, Transmission Operator, Distribution Provider and Load Serving Entity

Order No.	Utility	Description
G-141-10	POWELL RIVER ENERGY INC.	Mandatory Reliability Standards Registration as Generator Operator and Generator Owner
G-142-10	FORTISBC	2010 Annual Review and 2011 Revenue Requirements - Timetable for Workshop and Negotiated Settlement Process
G-143-10	PNG	Third Quarter 2010 Report on Gas Supply Costs
G-144-10	PNG(N.E.)	Third Quarter 2010 Report on Gas Supply Costs
G-145-10	TERASEN GAS	2010 Gas Supply Mitigation Incentive Program - Written Hearing and Timetable
G-146-10	TERASEN UTILITIES	2010 Long Term Resource Plan - Written Hearing and Timetable
G-147-10	FORTISBC	2010 Capital Expenditure Plan - Final Submissions Regulatory Timetable and Reasons
G-148-10	STARGAS	Alter Commodity Component of Rates and Consolidation and Extend Amortization of Term Financing
G-149-10	TERASEN GAS	Fort Nelson - 2011 Revenue Requirements - Notice of Written Hearing
G-150-10	TOLKO INDUSTRIES	Approval of Mitigation Plan Filings
G-151-10	TOBA MONTROSE	Approval of Mitigation Plan Filings
G-152-10	BC HYDRO	Approval of Mitigation Plan Filings
G-153-10	FORTISBC	Approval of Mitigation Plan Filings
G-154-10	TOBA MONTROSE	Mandatory Reliability Standards Registration for the functions of Generator Operator, Generator Owner, Transmission Owner, Transmission Operator
G-155-10	STARGAS	Gas Sales and Purchase Agreement with Cascadia and Application to Alter Commodity Component of rates and Approve Consolidation and Extend Amortization of its Term Financing
G-156-10	FORTISBC	2009 Rate Design Cost of Service Analysis -Decision
G-157-10	BC HYDRO	F2011 Revenue Requirements - Revised Regulatory Timetable
G-158-10	CITY OF NEW WESTMINSTER	Application by the City to be Deregistered for the Distribution Provider Function under MRS
G-159-10	ICBC	Approval of Consequential tariff Amendments to Reflect Changes to the Motor Vehicle Act
G-160-10	ICBC	Application to Standardize Trailer Basic Insurance Premiums

Order No.	Utility	Description
G-162-10	TGVI	Victoria Regional Operations Centre CPCN - Notice of Written Hearing and Regulatory Timetable
G-163-10	BC HYDRO	F2011 Revenue Requirements - Reinstate NSP and Suspend Revised Regulatory Timetable
G-164-10	BC HYDRO	General Wheeling Agreement between FortisBC and BC Hydro
G-165-10	TGVI	Issuance of Unsecured Debentures
G-166-10	BC HYDRO	Open Access Transmission Tariff Amendments - Written Review Process
G-167-10	BC HYDRO/BCTC	Assessment Report No. 2 - Determination of Reliability Standards for Adoption in BC
G-168-10	BCUC	Mandatory Reliability Standards -Role of Reliability Organization in British Columbia- Clarification
G-170-10	BCUC	Section 5 Inquiry – Toquaht First Nation Funding
G-171-10	BCUC	Mandatory Reliability Standards – the Western Electricity Coordination Council 2011 Implementation Plan
G-172-10	CORIX	Exemption from BC Hydro Two-Part Large General Service Rate - Written Hearing and Regulatory Timetable
G-173-10	TERASEN GAS	Fort Nelson Service Area - 2011 Revenue Requirements - Interim Rates and Deferral Account
G-174-10	PNG	Operating Line and Treasury/Commodity Hedge
G-175-10	PNG(N.E.)	Operating Line and Treasury/Commodity Hedge
G-176-10	BC HYDRO	Transmission Service Rate Customer Baseline F2010 and F0211 - Request for Comments
G-177-10	BC HYDRO	Hugh Keeleyside Spillway Project - Reasons for Decision
G-178-10	SUN PEAKS UTILITIES	Commodity Rate Changes
G-179-10	ICBC	Basic Insurance Housekeeping Tariff Amendments - Rating Territories for U-drive Trailers, Rate Class 024-Emergency Vehicles, Rate Class 120
G-180-10	BC HYDRO	F2011 Revenue Requirements Negotiated Settlement
G-181-10	TERASEN GAS	Compressed Natural Gas Service Agreement and General Terms and Conditions for Service for Compressed Natural Gas and Liquefied Natural Gas Service - Written Hearing & Regulatory Timetable
G-182-10	PNG	2011 Revenue Requirements – Preliminary Regulatory Timetable

Order No.	Utility	Description
G-183-10	PNG(N.E.)	2011 Revenue Requirements - Preliminary Regulatory Timetable
G-184-10	FORITSBC	F2011 Revenue Requirements - Negotiated Settlement
G-185-10	PNG	Natural Gas Commodity Charges Effective January 1, 2011
G-186-10	PNG(N.E.)	Natural Gas Commodity Charges Effective January 1, 2011
G-187-10	TERASEN GAS	2010 Fourth Quarter Gas Costs Report and Rate Changes Effective January 1, 2011 for the Lower Mainland
G-188-10	TERASEN WHISTLER	2010 Fourth Quarter Gas Cost Report and Rate Changes Effective January 1, 2011
G-189-10	TERASEN GAS	Revelstoke Service Area - 2010 Fourth Quarter Gas Cost Report and Rate Changes Effective January 1, 2011
G-190-10	TERASEN GAS	Fort Nelson 2010 Fourth Quarter Gas Cost Report and Rate Changes Effective January 1, 2011
G-191-10	TERASEN GAS	Application for Changes to the Customer Choice Program
G-192-10	BC HYDRO	Open Access Transmission Tariff Amendments – Reasons for Decision
G-193-10	CORIX	UniverCity Burnaby CPCN - Notice of Written Hearing and Timetable
G-194-10	TERASEN GAS	Biomethane Service Offering and Supporting Business Model - Salmon Arm Biomethane Project and Catalyst Biomethane Project - Decision
G-195-10	FORTISBC	2011 Capital Expenditures Plan - Decision
G-196-10	FORTISBC	Cost of Service Analysis - Reasons for Decision
G-197-10A	BC HYDRO	Approval of Mitigation Plan Filings
G-198-10A	FORTISBC	Approval of Mitigation Plan Filings
G-199-10A	TECK METALS	Approval of Mitigation Plan Filings
G-200-10	TOLKO INDUSTRIES	Approval of Mitigation Plan Filings
G-201-10	COLUMBIA POWER	Approval to Transfer MRS responsibilities to FortisBC Inc.
G-202-10	BC HYDRO	Application of its Large general Service to Pacific BioEnergy Prince George Limited Partnership
G-204-10	BC HYDRO	Residential Inclining Block Rate Re-pricing - Regulatory Timetable
G-1-11	PNG	Approval of an Amendment to Supplement No. 28 to Gas Tariff

Order No.	Utility	Description
G-2-11	TERASEN UTILITIES	Application to Revise the Administration and Invoicing of the Basic Charge
G-3-11	ZELLSTOFF CELGAR	Reconsideration of Commission Order G-156-10 and FortisBC 2009 Decision
G-4-11	BC HYDRO	Reconsideration of G-139-10 Transmission Service Rate – Customer Baseline Load F2009 and F2010 Dispute with Buckeye Canada
G-5-11	PLATEAU PIPE LINE	Application for Approval of the Western System Toll Changes
G-6-11	TERASEN GAS	Compressed Natural Gas and Liquefied Natural Gas - Reasons for Decision-Waste Management Section
G-7-11	TGVI	Mt. Hayes First Nations Investments - Notice of Written Hearing/Regulatory Timetable
G-8-11	PNG-WEST	2011 Revenue Requirements and Consolidated Gas Sales Tariff - Revised Timetable
G-9-11	PNG(N.E.)	2011 Revenue Requirements and Consolidated Gas Sales Tariff - Revised Timetable
G-10-11	PLATEAU PIPE LINE	Northeast BC Pipeline and Blueberry Pipeline Toll Decreases
G-11-11	FORTISBC	Issue Additional Common Shares
G-12-11	TERASEN GAS	Transfer of Ownership of the Pipe and Compression Facilities of the Southern Crossing Pipeline Project
G-14-11	TERASEN UTILITIES	2010 Long Term Resource Plan - Decision
G-15-11	BCTC/BC HYDRO	Reconsideration of the Interior to Lower Mainland Transmission Project
G-16-11	BC HYDRO	Disposition and Termination of BCTC Regulatory Accounts and BC Hydro's BCTC Deferral Account
G-17-11	COLUMBIA POWER CORPORATION	Application of Assignment Agreements to Transfer MRS Responsibilities from Arrow Lakes Power Corp., Brilliant Power Corp. and Brilliant Expansion to FortisBC Inc./Fortis Pacific Holdings Inc.
G-18-11	CORIX	Neighbourhood Utility Service at UniverCity CPCN - Amended Regulatory Timetable
G-19-11	PNG	Sale of its 50 Percent Interest in the Pacific Trail Pipelines Limited Partnership
G-20-11	BC HYDRO	Tariff Supplement No. 81 to BC Hydro's Open Access Transmission Tariff - AltaGas Northwest Projects Umbrella Agreement
G-21-11	CITY OF NELSON	Application for Approval of Electrical Utility Amendment By-Law No. 3181, 2011 Rate Increase

Order No.	Utility	Description
G-22-11	BC HYDRO	Application by BC Hydro for Acceptance of the Remote Community Electrification Program 2010 Annual Report
G-23-11	TERASEN GAS AND TGVI	Application for approval of the Price Risk Management Plan Effective April 2011-October 2014
G-24-11	FORTISBC	2009 Rate Design - Compliance Filing
G-25-11	FORTISBC UTILITIES	Application for Approval to Adopt US Generally Accepted Accounting Principles effective January 1, 2012
G-26-11	TERASEN GAS	Application for Approval of a Gas Supply Mitigation Incentive Program for November 1, 2010 to October 31, 2013 Three-Year Period - Reasons for Decision
G-27-11	TERASEN GAS	Application for Fort Nelson Service Area for Approval to Amend Schedule of Rates - Reasons for Decision
G-28-11	TERASEN GAS	Application by Terasen Gas Inc. for conversion of its Tariff to FortisBC Energy Inc. and Approval of FortisBC Energy Inc. Gas Tariff including General Terms and Conditions of Service and Rate Schedules effective March 1, 2011
G-29-11	TERASEN GAS	Application by Terasen Gas Inc. Fort Nelson Service Area for conversion of its Tariff to FortisBC Energy Inc. Fort Nelson Service Area and Approval of the FortisBC Energy Inc. Fort Nelson Service Gas Tariff including General Terms and Conditions of Service and Rate Schedules effective March 1, 2011
G-30-11	TGVI	Application by Terasen Gas (Vancouver Island) Inc. for conversion of Tariff to ForticBC Energy (Vancouver Island) Inc. and for Approval of the FortisBC Energy (Vancouver Island) Inc. Gas Tariff including General Terms and Conditions of Service and Rate Schedules effective March 1,2011
G-31-11	TERASEN WHISTLER	Application by Terasen Gas (Whistler) Inc. for conversion of its Tariff to FortsBC Energy (Whistler) Inc. and for Approval of the FortisBC Energy (Whistler) Inc. Gas Tariff including General Terms and Conditions of Service and Rate Schedules effective March 1, 2011
G-32-11	BC HYDRO	Transmission Service Rate - Customer Baseline Load F2010 and F2011 Dispute - Prince Rupert Port Authority - Written Hearing
G-33-11	BC HYDRO	Application to Amend Open Access Transmission Tariff Rate Schedule 09 Loss Compensation Service
G-34-11	BC HYDRO	Ruskin Dam and Powerhouse Upgrade Project Certificate of Public Convenience and Necessity Application - Notice of Hearing/Timetable
G-35-11	PNG	Sale of its 50 Percent Interest in the Pacific Trail Pipelines Limited Partnership - Determination

Order No.	Utility	Description
G-36-11	CORIX	Exemption from BC Hydro Two-Part Large General Service Rates - Reasons for Decision
G-37-11	INTERFOR	Adams Lake Lumber Division Application for a "Prospective Growth Adjustment" to the Historical Baseline of the British Columbia Hydro and Power Authority Large General Service Rates - Interim LGS Rate
G-38-11	FORTISBC	Application Request for Variance of Order G-195-10 in the 2011 Capital Expenditure Plan
G-39-11	CORIX	Neighbourhood Utility Service at UniverCity Certificate of Public Convenience and Necessity - Amended Regulatory Timetable
G-40-11	BC HYDRO	F2012-F2014 Revenue Requirements - Regulatory Timetable/Notice of Application, Workshop and Procedural Conference
G-41-11	BC HYDRO	F2012-F2014 Revenue Requirements - Interim Rates
G-42-11	CORIX	Application to Increase Gas Cost Recovery Charge for Propane Service for Panorama Mountain Resort
G-43-11	PNG(N.E.)	2010 Unaccounted for Loss Above 1.5 Percent for Fort St. John/Dawson Creek Division
G-44-11	BC HYDRO	Transmission Service Rate - Customer Baseline Load F2010 and F2011 Application
G-45-11	BC HYDRO	Residential Inclining Block Re-Pricing - Reasons for Decision
G-46-11	BC HYDRO	Application for Approval of Mitigation Plans
G-47-11	CATALYST PAPER CROFTON DIVISION	Application for Approval of Mitigation Plans
G-48-11	CATALYST PAPERELK FALLS	Application for Approval of Mitigation Plans
G-49-11	CATALYST PAPER POWELL RIVER	Application for Approval of Mitigation Plans
G-50-11	FORTISBC	Application for Approval of Mitigation Plans
G-51-11	POWELL RIVER ENERGY	Application for Approval of Mitigation Plans
G-52-11	RIO TINTO ALCAN	Application for Approval of Mitigation Plans
G-53-11	TECK METALS	Application for Approval of Mitigation Plans
G-54-11	TOLKO INDUSTRIES	Application for Approval of Mitigation Plans
G-55-11	PNG(N.E.)	Natural Gas Commodity Charges effective April 1, 2011 for the Forth St. John/Dawson Creek and Tumbler Ridge Service Areas

Order No.	Utility	Description
G-56-11	PNG	Natural Gas Commodity Charges effective April 1, 2011 for the PNG-West and Granisle Service Areas
G-57-11	FORTISBC	Variance of G-196-10 in the 2009 rate Design and Cost of Service Analysis
G-58-11	TOLKO INDUSTRIES	Reaffirmation of its Ability to Sell Power Generation in Excess of the First 2 MW of Generation in each hour as per OrderG-113-01
G-59-11	FORTISBC	Amend Existing Credit Facility Agreement
G-60-11	BC HYDRO	M.H. Customer Complaint - BackBilling
G-61-11	BC HYDRO	F2012-F2014 Revenue Requirements - Amended Regulatory Timetable
G-62-11	BC HYDRO	Suspend the Application of Certain Pricing Principles for Residential Inclining Block, Large General Service and Medium General Service Rates
G-63-11	KYUQUOT	Application for Exemption from Two-Part Large General Service e Rates
G-64-11	INTERFOR	Application for Adams Lake Lumber Division for a Prospective Growth Adjustment to Baselines Pursuant to Clause 13 of the Large General Service Negotiated Settlement Agreement
G-65-11	BC HYDRO	Ruskin Dam and Powerhouse Upgrade Project Certificate of Public Convenience and Necessity - Amended Regulatory Timetable
G-66-11	BCTC/BC HYDRO	Assessment Report No. 3 by British Columbia Hydro and Power Authority and the Determination of Reliability Standards for Adoption in British Columbia

CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

Order No.	Utility	Description
C-2-10	TERASEN GAS	Tilbury Property Purchase
C-3-10	BC HYDRO/BCTC	Vancouver City Central Transmission Project (BCTC) and VCCT Substation Distribution Assets (BCH)
C-4-10	TERASEN GAS	Operating Agreement with the Village of Midway
C-5-10	BC HYDRO/BCTC	Columbia Valley Transmission Project
C-6-10	TERASEN GAS	Operating Agreement with the Town of Princeton
C-7-10	TERASEN GAS	Operating Agreement (Franchise) with the Municipality of Coldstream
C-8-10	PNG	PNG/Village of Fraser Lake Franchise Agreement

Order No.	Utility	Description
C-9-10	TERASEN GAS	Upgrade of Transmission Pipeline Crossing of the Kootenay River near Shoreacres-approval
C-10-10	TERASEN GAS	Franchise Agreement Extension with the Corporation of the District of Peachland
C-1-11	TGVI	Victoria Regional Operations Centre - Reasons
C-2-11	TERASEN GAS	Extension to Franchise Agreement with Municipality of Coldstream
C-3-11	BC HYDRO	Tsay Keh Remote Community Electrification Project Application
C-4-11	BC HYDRO	Fort Ware Remote Community Electrification Project Application
C-5-11	BC HYDRO	Elhlateese Remote Community Electrification Project Application
C-6-11	FEVI	Victoria Regional Operations Centre - Final CPCN

ENERGY SUPPLY CONTRACTS

Order No.	Utility	Description
E-11-10	TERASEN GAS	Approval of the Special Provisions for the Cenovus Energy Inc. Gas EDI Base Contract
E-12-10	TERASEN GAS	Approval of the Special Provisions for the Sequent Energy Canada Corp. Gas EDI Base Contract
E-13-10	TERASEN GAS	Revelstoke – Approval of Propane Supply Agreement with MP Energy Partnership
E-14-10	TGVI	Baseload, Seasonal and Peaking Natural Gas Supply Contracts for 2009/10
E-15-10	TGVI	Natural Gas Supply Contracts for the period April 1 to October 31, 2010
E-16-10	TERASEN GAS	Natural Gas Supply Contracts for the period April 1 to October 31, 2010
E-17-10	TERASEN GAS	Approval of the Special Provisions for the United Energy Trading, LLC Gas EDI Base Contract
E-18-10	BC HYDRO	Filing of the Surplus Power Rights Agreement
E-19-10	BC HYDRO	Filing of an Electricity Purchase Agreement from the Standing Offer Program – Lower Bear Hydro, Upper Bear Hydro
E-20-10	TERASEN GAS	Application for Mist Storage Contracts and Related Delivery Agreement
E-21-10	TERASEN GAS	Amend and Extend the Northwest Natural Service Agreement for Firm Interstate Storage Service, Mist Storage Agreement No. D
E-22-10	TERASEN GAS	Revelstoke Propane Service Area - Price Risk Management Plan 2010-2011
E-23-10	TERASEN GAS	2010 Price Risk Management Plan (November 2010 - October 2013)

Order No.	Utility	Description
E-24-10	TGVI	2010 Price Risk Management Plan (November 2010 - October 2015)
E-25-10	TERASEN GAS	Nexen Marketing & J. Aron & Company Novation Agreement
E-26-10	TGVI	Nexen Marketing & J. Aron & Company Novation Agreement
E-27-10	TERASEN GAS	Completion of Hedging for Winter 2010/2011
E-28-10	FORTISBC	Electricity Purchase Agreement with Powerex Corporation
E-29-10	FORTISBC	Capacity Purchase Agreement with Waneta Expansion Power Corporation
E-30-10	SUN PEAKS	Propane Supply Agreement with MP Energy Partnership
E-31-10	BC HYDRO	Amending Agreements to Electricity Purchase Agreements for Cedar Road LFG and Canoe Creek Hydro
E-32-10	TERASEN GAS	Special Provisions for the Noble Americas Gas & Power Corp. Gas EDI Base Contract
E-33-10	PNG	2010/2011 Natural Gas Supply Contracts
E-34-10	TERASEN GAS	Storage Agreement with Aitken Creek Gas Storage ULC
E-35-10	TERASEN GAS	Storage Agreement with AECO
E-36-10	TGVI	Baseload, Seasonal and Peaking Natural Gas Supply Contracts for 2010/11
E-37-10	BC HYDRO	Amending Electricity Purchase Agreements
E-1-11	CORIX	Approval of a Propane Fuel Supply and Equipment Contract and a Fixed Price Rider for Panorama Mountain Resort
E-2-11	TERASEN GAS	Natural Gas Contracts for the Commodity and Midstream Portfolios for the 2010/11 Contract Year
E-3-11	BC HYDRO	Acceptance of Amending the Electricity Purchase Agreement between BC Hydro and Synex Energy Resource Ltd.
E-4-11	TERASEN GAS	Approval of the Special Provisions for the Nexen Marketing EDI Base Contracts
E-5-11	TERASEN GAS	Amending Agreement to the Synthetic Natural Gas Storage Agreement between Terasen Gas Inc. and Pacific Northern Gas Ltd.

PARTICIPANTS ASSISTANCE/COST AWARDS

Order No.	Utility	Description
F-12-10	BC HYDRO	Mica Gas Insulated Switchgear Project - $20,566.70
F-13-10	BC HYDRO	Gordon M. Shrum Units 1 to 5 Turbine Replacement Project - $16,375.38
F-14-10	TERASEN GAS	Customer Care Enhancements Project -$72, 934.76
F-15-10	BC HYDRO	Mica Gas Insulated Switchgear Project - $1,698.86
F-16-10	BC HYDRO	Waneta Dam Acquisition Reasons for Decision - $123,046.26
F-17-10	BCTC	Columbia Valley Transmission Project Ktunaxa Nation Council Interim Award - $12,843.50
F-18-10	PNG/PNG(NE)	Capital Structure and Equity Risk Premium - $9,103.50
F-19-10	BC HYDRO	Southern St'at'imc Electrification Project - $9,562.35
F-20-10	BCTC	Certificate of Public Convenience and Necessity for the Vancouver City Central Transmission Project - $22,913.83
F-21-10	ICBC	Changes to Universal Compulsory Automobile Insurance for Fleetplan Vehicles - $1,865.85
F-22-10	TERASEN GAS	Firm Transportation Service Agreement with Westcoast Energy Inc. and for Accounting Treatment of State 1 Costs for a Pipeline System Expansion Study - $2,118.38
F-23-10	TERASEN GAS	Tilbury Land Purchase CPCN and Tilbury Reconsideration of Order G-28-10 - $16,292.08
F-24-10	BCTC	F 2011 Transmission Revenue Requirement and Rate Changes - $3,774.75
F-25-10	BC HYDRO	Large General Service Rate - $311,280.36
F-26-10	BC HYDRO	Stave Falls Spillway Gates Replacement Project - $10,337.25
F-27-10	BC HYDRO	Hugh Keenleyside Spillway Gates - Interim Funding to Sinixt Nation Society - $3,264.80
F-28-10	ICBC	Streamlined Regulatory Process Setup - BCOAPO - $10,024.88
F-29-10	ICBC	2010 Revenue Requirements –BCOAPO - $7,847.44
F-30-10	TERASEN WHISTLER	2010-2011 Revenue Requirements - $51,097.07
F-31-10	FORTISBC	2009 Rate Design/Cost of Service - $291,296.48
F-1-11	TERASEN GAS	Upgrade of Transmission Pipeline Crossing of the Kootenay River near Shoreacres CPCN - $5,509.00
F-2-11	FORTISBC	2011 Revenue Requirements and Negotiated Settlement Process – $24,694.56

Order No.	Utility	Description
F-3-11	TERASEN GAS	Approval of a Gas Supply Mitigation Incentive Program for the November 1, 2010 to October 31, 2013 Three-Year Period - $17,536.33
F-4-11	FORTISBC	2009 Rate Design/Cost of Service - Amended Award for Mr. Shadrack - $1,730.02
F-5-11	TERASEN GAS	Biomethane Service Offering and Supporting Business Model - $29,575.90
F-6-11	BC HYDRO/BCTC	Columbia Valley Transmission Project - $21,521.79
F-7-11	BC HYDRO	Hugh Keenleyside Spillway Gates Project - $12,546.22
F-8-11	FORTISBC	2011 Capital Expenditures Plan – $28404.75
F-9-11	FORTISBC	2010 Annual Review, 2011 Revenue Requirements - Denied
F-10-11	TERASEN UTILITIES	2010 Long Term Resource Plan - $30,670.18
F-11-11	FORTISBC	Application to Amend Schedule of Rates for the Fort Nelson Service Area for Participant Assistance/Cost Award - $3,869.60
F-12-11	BC HYDRO /BCTC	Interior to Lower Mainland Transmission Project – Reconsideration - $395,844.79
F-13-11	BC HYDRO	F2010-11 Revenue Requirements - $286,267.16
F-14-11	FEVI	Victoria Regional Operations Centre - $8,467.72

COMMISSION LETTERS

Order No.	Utility	Description
L-28-10	PNG/ PNG(N.E.)	Capital Structure and Equity Risk Premium – Amended Regulatory Timetable
L-29-10	BCTC	Interior to Lower Mainland Transmission Project – Exhibit A-23 - Video Evidence
L-30-10	BIRDS EYE COVE ESTATES	CPCN, Revenue Requirements and Tariffs – Amended Timetable
L-31-10	FORTISBC	Complaint by Greg Wozny - Ymir Power Surge – Request to FortisBC
L-32-10	FORTISBC	Complaint by Melody Farmer – Power Surge near Boswell – Request to FortisBC
L-33-10	BC HYDRO	Request to Amend Directive 31 of the 2008 Long-Term Acquisition Plan Decision – Guidelines regarding Major Threshold Projects –Deferral of Filing Date
L-34-10	BCTC	Interior to Lower Mainland Reconsideration – Reply Argument Extension
L-35-10	BCTC	Columbia Valley Transmission CPCN Project – Cancellation of Workshop and Community Input Session

Order No.	Utility	Description
L-36-10	ACTIVE ENERGY	Code of Conduct – Allegations of Forgery – Notice to Appear at the Commission Office
L-37-10	BIRDS EYE COVE ESTATES	Certificate of Public Convenience and Necessity Application, Revenue Requirements and Tariffs – Amended Regulatory Timetable to allow BECP to Respond to Information Requests (Exhibit A-9)
L-38-10	BC HYDRO	Sinixt Reconsideration of Order G-12-10 and Reasons for Decision regarding the BC Hydro Waneta Acquisition
L-39-10	TERASEN GAS	Terasen Gas Customer Choice Program – 2010 Advertising Review
L-40-10	BC HYDRO	F2011 Revenue Requirements – Amended Timetable
L-41-10	PLATEAU	End of Life Issue – Order P-4-09 Compliance Filing
L-42-10	PNG	Price Risk Management Plan dated April 2010
L-43-10	BC HYDRO	Waneta Dam Acquisition - Adjust Fiscal 2011 Revenue Requirements Application regarding Final Actual Transaction Costs
L-44-10	FORTISBC	2009 Rate Design - Zelstoff Celgar Information Request to FortisBC Exhibit A-26
L-45-10	BCTC	Cancellation of Annual Network Economy Meeting for 2010
L-46-10	TGVI	Second Quarter Gas Costs/Annual Revenue Surplus Deficiency
L-48-10	PNG	Second Quarter Gas Costs for PNG-West and Granisle
L-49-10	PNG(N.E.)	Second Quarter Gas Costs for Fort St. John/Dawson Creek and Tumbler Ridge Divisions
L-50-10	SHAW CABLESYSTEMS	Continued Use of FortisBC Transmission System - Extension to Filing Date for Information Requests (Exhibit A-12)
L-51-10	FORTISBC	F2011 Revenue Requirements and Rate Design - Regulatory Timetable (Exhibit A-27)
L-52-10	BIRDS EYE COVE ESTATES	Certificate of Public Convenience and Necessity and Revenue Requirements Tariff - Extension to Regulatory Process (Exhibit A-10)
L-53-10	BCUC	Mandatory Reliability Standards - Guidelines for Filing Mitigation Plans
L-54-10	ACTIVE ENERGY	Allegations of Forgery/Unauthorized Signatures
L-55-10	SUMMITT ENERGY	Denied Third Party Verification Script Amendment - Request Wording Change Regarding Green Energy Option
L-56-10	BC HYDRO	Large General Service Rate Application – Extension to Tariff Filing Date in Order G-110-10
L-57-10	BIRDS EYE COVE ESTATES	Certificate of Public Convenience and Necessity and Revenue Requirements Tariff - Extension to Regulatory Process

Order No.	Utility	Description
L-58-10	FORTISBC	Customer Complaint - Greg Wozney - Ymir Power Surge and Incident Report
L-59-10	FORTISBC	Customer Complaint - Melody Farmer - Boswell Power Surge and Incident Report
L-60-10	BC HYDRO	Reporting of Forced Outage (January 2009) Power Surge in Mission/Stave Falls Area
L-61-10	ICBC	Confidential Filing of Chapter 9 of the 2010 Streamlined Revenue Requirements Application
L-62-10	TERASEN GAS	2010/11 Annual Gas Contracting Plan - November 2010-October 2011
L-63-10	TGVI	2010/11 Annual Gas Contracting Plan - November 2010-October 2011
L-64-10	FORTISBC	2011 Capital Expenditure Plan - Amended Regulatory Timetable - Intervener Information Requests No. 1
L-65-10	CLOUDWORKS	Extension to Filing of Mitigation Plan to September 30, 2010
L-66-10	FORTISBC	2011 Capital Expenditure Plan - Amended Regulatory Timetable - FortisBC Responses to BCUC & Information Requests No. 2
L-67-10	FORTISBC	2009 Rate Design - Oral Phase of Argument: Panel Questions / Topics for Submissions
L-68-10	BIRDS EYE COVE ESTATES	Certificate of Public Convenience and Necessity/Revenue Requirements and Tariff - Extension to Regulatory Process
L-69-10	BCUC	Section 5 Inquiry - Response to Woodward and Company regarding Late Applications for Participant Assistance/Cost Awards for the Toquaht First Nation, Cowichan Tribes, Liard First Nation, and Tsawout First Nation
L-70-10	TERASEN GAS	2010 Third Quarter Gas Cost Report - Lower Mainland, Inland and Columbia - Commodity Cost Reconciliation Account/Midstream Cost Reconciliation Account
L-71-10	TERASEN GAS	Revelstoke 2010 Third Quarter Propane Costs
L-72-10	TERASEN GAS	Fort Nelson 2010 Third Quarter Gas Costs
L-73-10	TERASEN WHISTLER	Whistler 2010 Third Quarter Gas Costs
L-74-10	TGVI	2010 Third Quarter Report on Gas Cost Variance Account and the Rate Stabilization Deferral Account
L-75-10	IPPBC	Reconsideration of F-16-10 BC Hydro Waneta Transcations - Reasons for Decision
L-76-10	TOLKO INDUSTRIES	Reconsideration of Commission Order G-95-10A
L-77-10	SMART ENERGY	Request for Revised Customer Agreement

Order No.	Utility	Description
L-78-10	TERASEN GAS	Expedited Review and Approval of Northwest Pipeline Company Capacity Release from Northwest Natural to Terasen Gas
L-79-10	SMART ENERGY	Marketing Material - Information Request
L-80-10	TERASEN GAS	Extension of Nova Gas Transmission Service Contracts for 5 Years
L-81-10	TERASEN GAS	Receipt Point Fuel Gas Percentages
L-82-10	BLUESTREAM ENERGY	Information Request - Consumer Agreement, Financial Statements
L-83-10	DIRECT ENERGY	Information Request - Consumer Agreement
L-84-10	ACCESS GAS	Information Request - Financial Statements
L-85-10	BIRDS EYE COVE ESTATES	Revenue Requirements and Tariff-Request to Participant
L-86-10	BC HYDRO	F2011 Revenue Requirements - Request for Comments
L-87-10	FORTISBC	2011 Capital Expenditure Plan/Exhibit A-8 Revised Regulatory Timetable
L-88-10	BIRDS EYE COVE ESTATES	Extension Intervener Evidence Filing - Coalition
L-89-10	FORTISBC	2010 Annual Review/2011 Revenue Requirements - Shaw Late Intervention Reasons for Decision
L-90-10	BC HYDRO/BCTC	Interior to Lower Mainland Transmission Line Reconsideration - Request for Submissions regarding Carrier Sekani Judgement
L-91-10	BC HYDRO	Reconsideration of 2007 Alcan EPA - Proceeding Closed
L-92-10	TGI-FT NELSON	2010 Revenue Requirements -Amended Regulatory Timetable
L-93-10	BIRDS EYE COVE ESTATES	Certificate of Public Convenience and Necessity, Revenue Requirements and Tariffs – Amended Timetable
L-94-10	BC HYDRO	Transmission Service Rate Customer Baseline F2010 and F0211 - Request for Comments
L-95-10	FORTISBC	2009 Rate Design - Request for comments on revised COSA
L-96-10	TERASEN UTILITIES	Harmonized Sales Tax Impacts on Revenue Requirements
L-97-10	JUST ENERGY	Inbound Blend and Extend Script Approval
L-98-10	TERASEN GAS	Fort Nelson 2011 Revenue Requirements - Revised Timetable

Order No.	Utility	Description
L-99-10	FORTISBC	Zellstoff-Celgar Reconsideration of the 2009 Rate Design Decision
L-100-10	TGVI	2010 Fourth Quarter Report on the Gas Cost Variance Account and the Rate Stabilization Deferral Account
L-101-10	BIRDS EYE COVE ESTATES	Certificate of Public Convenience and Necessity and Revenue Requirements Tariff - Amended Regulatory Timetable
L-102-10	PNG	2011- Revenue Requirements - Regulatory Timetable Suspended
L-103-10	PNG(N.E.)	2011- Revenue Requirements - Regulatory Timetable Suspended
L-104-10	BC HYDRO	Tappenvale Farm Stray Voltage Complaint- Regulatory Timetable
L-1-11	BC HYDRO	Remote Community Electrification Program
L-2-11	ICBC	Streamline Regulatory Process
L-3-11	BC HYDRO	Tappenvale Farm Stray Voltage Complaint - Timetable Suspended
L-4-11	BIRDS EYE COVE ESTATES	Coalition Complaint re: Notice of Disconnection to Customers
L-5-11	CORIX	Exemption from BC Hydro Large General Service Rate - BC Hydro Sur-reply
L-6-11	PNG-WEST	2011 Revenue Requirements - Amended Timetable
L-7-11	PNG(N.E.)	2011 Revenue Requirements - Amended Timetable
L-8-11	BIRDS EYE COVE ESTATES	Coalition Complaint Resolution
L-9-11	BC HYDRO	F2011 Revenue Requirements - Adjustment to PACA Re Applications Requested
L-10-11	BCUC	Mandatory Reliability Standards Clarification on the Relevance of North American Electric Reliability Corporation Rules of Procedure and Alerts
L-11-11	BCTC/BC HYDRO	NNTC/ONA/Upper Nicola - Interior to Lower Mainland Transmission Project - Certificate of Public Convenience and Necessity Application for Reconsideration of ILM Decision
L-12-11	FORTISBC ENERGY	Lower Mainland, Inland and Columbia Service Areas 2011 First Quarter Gas Cost Report Commodity Cost Reconciliation Account and Midstream Cost Reconciliation Account
L-13-11	FORTISBC WHISTLER	Whistler Service Area - 2011 First Quarter Gas Cost Report
L-14-11	FEVI	FortisBC Energy (Vancouver Island) Inc. - 2011 First Quarter Report on the Gas Cost Variance Account and Rate Stabilization Deferral Account
L-15-11	FORTISBC ENERGY	Revelstoke Propane Service Area 2011 First Quarter Report

Order No.	Utility	Description
L-16-11	FORTISBC ENERGY	Fort Nelson Service Area 2011 First Quarter Report
L-17-11	PNG	2011 Revenue Requirements and Consolidated Gas Tariffs - Regulatory Timetables for the revenue requirements-NSP and Consolidated Gas Tariffs-Written Process
L-18-11	PNG(N.E.)	2011 Revenue Requirements and Consolidated Gas Tariffs - Regulatory Timetables for the Revenue Requirements - NSP and Consolidated Gas Tariffs-Written Process
L-19-11	BC HYDRO	F2012-2014 Revenue Requirements - Procedural Issues
L-20-11	FORTISBC ENERGY	Report on Gas Cost Deferral Accounts and Rate Setting Mechanisms
L-21-11	BCTC/BC HYDRO	ILM Decision Reconsideration - Request for Submissions
L-22-11	PNG-WEST	2011 Revenue Requirements - Amended Timetable
L-23-11	PNG(N.E.)	2011 Revenue Requirements - Amended Timetable
L-24-11	BCTC/BC HYDRO	Interior to Lower Mainland Transmission Project Decision Reconsideration - Request for Comments
L-25-11	BC HYDRO	F2012-F2014 Revenue Requirements – Adjournment No. 2 - Amended Timetable
L-26-11	BIRDS EYE COVE ESTATES	Certificate of Public Convenience and Necessity for Revenue Requirements and Tariffs - Amended Timetable

STANDARD ABBREVIATIONS & ACRONYMS

Allowance for Funds Used During Construction	AFUDC
Alternative Dispute Resolution	ADR
Apartment Customer Rates	ACR
Big White Utility Ltd.	Big White
British Columbia Hydro and Power Authority	BC Hydro
British Columbia Transmission Corporation	BCTC
Cal-Gas Inc.	CalGas
Central Heat Distribution Limited	Central Heat
Certificate of Public Convenience and Necessity	CPCN
Corix Multi-Utility Services Inc.	Corix
Energy for our Future: A Plan for BC	Energy Plan or Energy Policy
FortisBC Inc.	FortisBC
Gas Cost Reconciliation Account	GCRA
Gas Cost Variance Account	GCVA
Hemlock Valley Electrical Services Limited	Hemlock Valley
Independent Power Producers	IPPs
Insurance Corporation of British Columbia	ICBC
Kinder Morgan, Inc.	Kinder Morgan
Kyuquot Power Ltd.	Kyuquot Power
Large General Service	LGS
Natural Gas Marketers	NGM
Natural Gas Vehicles	NGV
Negotiated Settlement Process	NSP
Pacific Northern Gas (N.E.) Ltd.	PNG (N.E.)
Pacific Northern Gas Ltd.	PNG, PNG-West
Plateau Pipe Line Ltd.	Plateau
Port Alice Gas Inc.	Port Alice Gas
Return on Common Equity	ROE
Silversmith Light & Power Corporation	Silversmith
Small General Service	SGS
Stargas Utilities Ltd.	Stargas
Sun Peaks Utilities Co., Ltd.	Sun Peaks
Sun Rivers Services Corp.	Sun Rivers
FortisBC Energy (Vancouver Island) Inc.	FEVI
(formerly Terasen Gas (Vancouver Island) Inc.	Terasen VI, TGVI
FortisBC Energy (Whistler) Inc. (formerly Terasen Gas (Whistler) Inc.	Terasen Whistler, TGW, FEW
FortisBC Energy Inc. (formerly Terasen Gas Inc.)	Terasen, Terasen Gas, TGI, FEI
The Corporation of the City of Nelson	City of Nelson
The Yukon Electrical Company Limited	Yukon Electrical
Trans Mountain (Jet Fuel) Inc.	Trans Mountain
Utilities Commission Act	the Act, UCA

GLOSSARY OF TERMS

allowance for funds used during construction (AFUDC) The amount a regulated entity is allowed to earn to recover its cost of financing assets under construction. AFUDC is equal to the average cost of the construction work in process, times a financing rate which is usually equal to the entity's cost of capital rate. AFUDC is not recovered immediately through rates; it is included in the cost of the related assets and recovered in future periods through the depreciation charge.

allowed rate of return The rate of return a regulated entity is allowed the opportunity to earn. When applied to the rate base, the allowed rate of return provides an amount equal to the cost of financing the investment required for regulated operations. The financing costs include both the cost of debt and the cost of equity.

alternative dispute resolution (ADR) *See negotiated settlement process.*

application for reconsideration An application to have the Commission reconsider, vary, or rescind a decision or order previously issued.

burnertip rate The rate charged for gas at the customer's meter, including the delivery charge, fixed monthly charge and gas commodity charge. It is usually calculated as an annual average rate based on typical annual consumption for the customer class.

capital cost The fixed costs associated with the construction of an energy facility, including land and siting costs, material and labour costs, allowance for funds used during construction, and other applicable overhead charges.

cogeneration The generation of electric power in conjunction with the use of steam in an industrial or space heating process, using waste heat from one process to drive the other. Cogeneration is more efficient compared to traditional thermal generating plants.

commercial commodity unbundling (also see *residential commodity unbundling*) The program provides commercial customers (Rates 2, 3 and 23) of Terasen Gas Inc. with the opportunity to enter into a natural gas commodity supply arrangement with a licensed gas marketer.

common carrier(s) An energy transportation provider, typically a crude oil or natural gas pipeline which provides service on a non-discriminatory basis to all potential shippers.

cost of service The total cost of providing service, including operating and maintenance expenses, depreciation, amortization, taxes and cost of capital. The cost of service is also known as *revenue requirements*.

cost of service study A study to determine the cost of service by class of service and/or customer. These studies are used to help determine how the revenue requirements are to be allocated among the rates for the various services/customers.

cross subsidization Increasing the rates for one service or class of customers so the rates of another service or class of customers can be reduced below cost.

debt-equity ratio The ratio of money borrowed by the utility to money invested in the utility by shareholders. There is a theoretical optimum for this for each utility.

deferral account An account that records the deferral of a cost or revenue until a future date. A deferred asset account records a cost that would normally be expensed and recovered in the current period, but which is to be expensed or recovered in a future period. A deferred liability account records an amount recovered in the current period, to cover costs of providing service in a future period.

demand-side management (DSM) Efforts to modify customer demand patterns by either increasing end-use energy efficiency or reducing fluctuations in energy demand.

distributed generation Generation that is relatively small scale and located close to the final customer.

distribution system The portion of an electric or natural gas transportation infrastructure that connects end-users to bulk production or transportation facilities.

energy losses Energy lost during transportation from suppliers to end-users. Energy losses on a typical natural gas system are around 1 to 3 percent. Energy losses on a large electric system are around 5 to 8 percent.

export sales Bulk sales of electricity or natural gas outside of British Columbia.

firm capacity The amount of instantaneous energy production or transportation capacity that is available at a defined time.

firm energy The amount of energy that is available over a defined period of time.

fixed cost Costs associated with an energy production or transportation facility which must be paid whether the plant operates or not. Fixed costs generally include capital costs, contract demand charges and operating costs which are committed or unaffected by production levels.

gas cost reconciliation account (GCRA) / gas cost variance account (GCVA) A deferral account which accumulates the variance in actual gas costs from the actual gas revenue recovered in customer rates.

green power rates Rates charged for electricity service from generators which do not pollute or damage the environment. Different groups define "green" power with various levels of restriction. For example, a run of the river hydro plant may be included while a new dam and reservoir may be excluded.

hydroelectric energy, hydroelectricity Electric energy produced by water falling through a turbine generator. In British Columbia, hydroelectricity is the dominant form of electric energy production.

incentive regulation Regulation which rewards utilities for cost savings or other actions which are desired by ratepayers.

independent power producers (IPPs) Non-utility electric energy generators. Until the early 1970s, independent power producers were rare. With recent changes in utility technology and economics, they have become more common. Many issues relating to restructuring of the utility industry involve the role of independent power producers in a deregulated energy market.

information requests Questions posed to those who have filed evidence for a hearing, pertaining to the evidence they have filed. Information requests and their responses are made prior to the hearing, in writing, and become evidence in the hearing. Information requests are also referred to as "interrogatories".

interim rate A rate which is put in place until the regulator can determine the final rates. If the final rates are lower than the interim rates, customers are generally refunded their over-contributions with interest for the period of time the interim rates existed.

interruptible energy, interruptible service Energy flow which can be reduced or cut off on relatively short notice when needed by other customers. Generally, interruptible energy is sold by contract at a reduced price or without fixed charges to end-users, with specific terms and conditions governing interruptibility rights.

investor-owned utility A utility owned by private shareholders.

joule A measure of energy or work done equal to a force of 1 newton applied through a distance of 1 metre. One gigajoule (one billion joules) is roughly equal to energy from 915 cubic feet of natural gas, 29 litres of gasoline, or 278 kWh of electricity.

kilowatt-hour 1,000 watt-hours.

load The amount of energy required by end-users on a given portion of the system at a given time. Load originates primarily at customers' energy-consuming equipment.

load growth Increase in the demand for energy.

load-resource balance The point at which demand for energy exactly equals energy production.

local distribution company (LDC) A utility (natural monopoly) that owns and operates the local delivery network for commodities such as electricity, natural gas and water. In a vertically integrated utility, local delivery is just one of several functions (e.g., BC Hydro). Thus, a LDC only exists when the delivery function has been vertically de-integrated (e.g., Terasen Gas).

market-based rates Prices set freely in a competitive market, rather than prices based on costs of production.

megawatt (MW) 1,000 kilowatts, or 1,000,000 watts.

natural monopoly An industry whose market output is produced at the lowest cost when production is concentrated in the hands of a single firm. The term utility is sometimes applied synonymously with natural monopoly.

natural gas marketer (NGM) (also see *residential/commercial commodity alternative unbundling*) Under the Commodity Unbundling program, natural gas marketers are independent businesses that offer gas supply choices to customers such as different terms and conditions. To be able to sell gas under the Commodity Unbundling program, gas marketers must be licensed by the British Columbia Utilities Commission and adhere to the Code of Conduct for Gas Marketers (see *http://www.bcuc.com/NaturalGasMarketers.aspx*)

negotiated settlement process (NSP) A less formal process than a public hearing, and one where the applicant, interested parties and Commission staff meet to review and attempt to negotiate a settlement on some or all aspects of an application. NSP is used as a complement or an alternative to the traditional regulatory process (e.g., oral public or written hearings) in an effort to save time and reduce the cost of utility regulation while achieving sound regulatory outcomes.

peaking gas Gas which is stored or purchased under contracts which will allow delivery during the periods of highest demand.

performance-based rates See *incentive regulation*.

petajoule (PJ) 10^{15} or one quadrillion joules.

quasi-judicial The powers and processes of a regulator which are similar to the courts.

rate base The amount of investment in regulated operations on which a regulated entity is allowed to earn a return. It usually consists of the depreciated value of the plant in service required for regulated operations plus an allowance for working capital and deferred assets.

rate design The methodology for apportioning the revenue requirement to the various classes of utility customers.

rate rider A specific charge on a customer's bill to recover a specific cost over a fixed period of time.

ratepayers The customers of a utility.

rates The prices at which regulated services are provided.

real time pricing (RTP) Variable pricing of electricity in which the price depends on the cost or market value of providing electricity during each time segment. Applying RTP to electricity service results in customer rates that vary according to the specific utility costs at various times.

residential commodity unbundling (also see *commercial commodity unbundling*) The program provides residential customers (Rate 1) of Terasen Gas with the opportunity to enter into a natural gas commodity supply arrangement with a licensed gas marketer.

retail competition Permitting end-use energy customers to contract directly with energy suppliers for their electricity or natural gas commodity, while continuing to deal with transmission and distribution utilities for the commodity delivery. The energy commodity is generally sourced in a competitive marketplace.

return on equity (ROE) The percentage return allowed for the invested equity of utility shareholders.

revenue requirements See *cost of service*.

self-generation Generation of electricity by a customer for part or all of its own load requirements.

spot market A real-time commodity market for immediate sale and delivery of energy products.

transmission grid, transportation grid, transmission system An interconnected system of high voltage energy transportation lines and associated facilities used for bulk transfers of electricity. A high-pressure pipeline used for bulk transfers of natural gas is also referred to as a transmission system.

watt The power required to do work at the rate of one joule per second.

watt-hour One watt-hour is equal to 3,600 joules of energy.

wheeling The service of delivering electricity across a transmission system for a third party.

wholesale markets Wholesale electricity markets are comprised of transactions between buyers and sellers of bulk power at points on a high voltage transmission system.

wholesale rates The unit prices charged for bulk energy services.

ENERGY CONVERSION FACTORS

Fuel Type	Original Measure	Terajoules
Coal	1 kilotonne	29.53
Coke	1 kilotonne	28.83
Petroleum Coke	1 megalitre	42.38
Natural Gas	1 gigalitre	38.35
Crude Oil	1 megalitre	38.51
Diesel Fuel Oil	1 megalitre	38.67
Light Fuel Oil	1 megalitre	38.67
Heavy Fuel Oil	1 megalitre	41.73
Aviation Gasoline	1 megalitre	33.52
Aviation Turbo Fuel	1 megalitre	35.93
Propane	1 megalitre	25.50
Butane	1 megalitre	28.60
Hydro-electricity	1 gigawatt hour	3.60
Thermal Electricity	1 gigawatt hour	3.60
Hog Fuel	1 megalitre SWE*	7.69 - 9.10

* SWE = solid wood equivalent

Kilo	10^3	1 megalitre	1,000 cubic metres
mega	10^6	1 Btu	1054.615 joules
giga	10^9	1 barrel	0.15891 cubic metres
tera	10^{12}	1 cubic foot	0.02832784 cubic metres
peta	10^{15}	1 gallon	4.54609 litres
		1 cubic foot of natural gas	1-3- Btus

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